Energy UK Gas Retail Group Study into the effect of shrinkage on domestic customers

Final Report

Version 5

IC Consultants Ltd

For Energy UK

October 2015

Imperial College London Consultants

Title	Deliverable 4: Final Report
Client	Energy UK
Date	23 October 2015
Authors	**Imperial College Consultants**: Nilay Shah, Niall Mac Dowell, Sergei Kucherenko
Version	V5
Distribution	GRG group, Energy UK

Contents

1 Executive Summary

The overall brief for this project was to study the determination and calculation of shrinkage and to review the methodology used to calculate gas shrinkage and assess whether it needs updating or improving.

The methodology followed was based on a review of:

- The technical and regulatory literature produced by the regulator and operators in the UK
- Similar literature for other jurisdictions
- The open academic literature
- Material from other industry sectors (e.g. water, offshore oil and gas).

These were coupled with some engineering analysis of the data and published models.

This report has reviewed:

- The GDN shrinkage and leakage model and its input factors
- Similar models and factors used elsewhere
- Evidence from a variety of leakage measurements
- Practices in other industries
- Regulation and policy around shrinkage

These are some of the key findings:

Model

- The model is most sensitive to
    - the metallic length
    - the leakage rate for the metal service connected to metal main
    - the number of relays per km
    - the leakage rates of polyethylene (PE) mains
- There is evidence that a zero leakage rate (as assumed by the model) for polyethylene services is highly unlikely in practice (although this number is low)
- The sample-based approach from the 2002 study to generate the leakage factors is likely generate a bias towards underestimation as the leakage rate distribution is skewed, with large amounts of leakage being caused be relatively few leaks in large systems; such leaks could be missed in small samples.
- We have found that there are some important anomalies in the shrinkage model which are not consistent with theory; that some of the data are not in line with international estimates and some assumptions border on the optimistic. It has been over 12 years since the last calibration study and it would be reasonable to request another one, especially considering the intervening improvements in technology.

- More evidence to justify the network composition assumptions should be made available to shippers and other stakeholders to generate more confidence in the SLM. We were not available to find evidence on network composition on the gas governance website.
- The elapsed time means that knowledge of how the model was developed and the assumptions made and procedures for model maintenance are not as clear as they could be.
- Note that the same model is used in each region/area.

Measurements

- There is evidence from an review of actual international methane emission measurements in cities that reported leakage rates based on estimation models underestimate actual leakages. For example, a London study described in section 4.2 indicates that actual leakage rates could be up to three times higher.
- This will of increasing concern as countries will be required to provide increasingly accurate greenhouse gas (GHG) emissions inventories. For example, DEFRA/DECC must provide such statistics to the European Commission and UNFCC.

Regulation/Policy

- The Shrinkage Allowance and Environmental Emissions Incentive have had some effect on improved system pressure management which has had a moderate impact but may increasingly not deliver the desired effect.
- The HSE based IMRP (REPEX) process has potentially had a larger impact on shrinkage than the Ofgem shrinkage allowance and emissions based incentives, although both policies generate similar outcomes. Around 80% of the shrinkage reduction arises out of mains replacement.
- The model assumptions around iGTs are leading to an underestimate of shrinikage: iGTs started off as a small part of the system but they are now quite substantial and efforts should be made to include them properly in the estimation of shrinkage and to require the relevant reporting. There are around 1.5 million meter points and the actual shrinkage could constitute up to 2-5% of the current estimate, i.e. £1.4-3.5m. Furthermore, no figures are available for estimates of third party damage/interference; it may be expected that relatively higher amounts of excavation are taking place in iGT areas as they are areas of new development.

Possible Developments in Accuracy Improvement

- The water industry equates leakage rate estimation with unaccounted for supply and bases it on actual measurements using on the balance between water entering the network and that consumed. A total/integrated flow method is used for the whole network and a “night-flow” method for smaller sub-networks.
- The oil and gas production industry uses “age factors” to indicate that older equipment is expected to have higher leakage rates. This could be particularly relevant to AGIs and preheaters. It also applies temperature and pressure corrections which could be used to improve shrinkage estimates. Finally, it has developed a range of leak detection and

measuring methods (e.g. IR detection, bagging) which might be exploited in distribution networks.

- The Netherlands survey their GDNs every 5 years, leading to good quality network composition data (less than 0.4% unknown). This is an example of best practice.

Core Recommendation

It has been over 12 years since the last calibration study and it would be reasonable to request another one, especially considering the intervening improvements in technology. Although the cost might be of the order of £10m, when compared to the uncertainty of the shrinkage measures the figure is not large. For example, it could easily be argued that the shrinkage estimate error is at least 20% which is of the order of £15m p.a. (based on a total estimate of £75m p.a.), hence the uncertainty resolution cost which would apply over several years is very low compared to the level of uncertainty. The cost may be reduced through new non-invasive technologies as well (or semi-invasive methods such as the "suction method" used in the Netherlands study[xlvi] described later in this report); these could be evaluated using low carbon innovation network funding. Furthermore, this is important for the National Emissions Inventory which must be reported by DEFRA every year.

It has been stated that an updated study might be made redundant by smart meters, however since these may be able to evaluate shrinkage more accurately but not apportion it and hence not lead to actionable data, this should not be the case. The new study would therefore be future proof. This could be coupled with periodic, non-invasive leak detection activities.

This could be co-managed/supported by stakeholders interested in better national emissions inventories (e.g. DECC/DEFRA) and the means to reduce emissions.

2 Background and project brief

Background to Study

The Gas Retail Group (GRG) identified the need for a study which looks into, and quantifies, the effect of gas shrinkage on domestic customers. Currently, gas is measured at the off take meter as it flows from the National Transmission System (NTS) to the Local Distribution Zones (LDZs). Most gas consumed is metered, however, some gas is lost and unaccounted for between the offtake meter and consumer supply point due to, amongst other things, theft, leakage, and own use gas. All of these, while being precisely unknown, are modelled and estimated by GDN operators. The current arrangements under the UNC allocate charges to shippers based on the volume of gas transported. This methodology ultimately sees all lost, stolen, and own use gas allocated across the whole market.

Reforming the settlement arrangements is being addressed through Project Nexus, however the GRG see the need for a piece of work looking into the effects of shrinkage on charges made to shippers.

Study Requirements

The GRG agreed that a study into the determination and calculation of shrinkage should be commissioned to review the methodology used to calculate shrinkage and assess whether it needs updating or improving. The group agreed that it should be carried out by an independent expert to ensure the outcome is not prejudiced in any way and has a high level of credibility moving forward.

The study requirements have been split into two areas as some elements will require the cooperation of Gas Distribution Networks (GDNs), whereas some will be able to be undertaken unilaterally and with publicly available material.

Study requirements able to be conducted unilaterally:

- Analyse the current allocation methodology to determine if the GDN allocation is sufficient and fair, and whether an incentives based system would be beneficial to shippers;
- Compare how losses are accounted for, assessed and incentives applied in other utility industries e.g. electricity and water, and how they differ from the gas. Consideration of the way losses are accounted for in offshore oil and gas would also be beneficial.

Study requirements which will require GDN cooperation:

- Look at the assumptions used to calculate the estimates for leakage, gas theft and own use gas to determine if they are relevant and up to date and the best means of calculation/evaluation;
- Evaluate the effect and extent of infrastructure characteristics on shrinkage, for example, the ‘leak-proof’ assumptions of plastic pipes, and, the effect of undulations and subsidence on the integrity of pipeline joints and leakage;

  [during the project it was found that these did not need GDN cooperation as there was sufficient data in the public domain]
- Establish the effects of the characteristics of metal pipes, and the degree to which they are used in modelling and whether assumptions are correct, and the degree to which they

should be used in modelling i.e. whether the level of replacement of metal pipes is accurately reflected in modelling and assumptions;

- Consider what mechanisms are in place to verify the accuracy of mains replacement activity, both in terms of the network maps on location of PE pipes, but assurance that the mains have indeed been replaced.
- Analyse the impact of Independent Gas Transporters (iGTs) on shrinkage assumptions.

  [similarly, there was enough data in the public domain to perform this]
- Determine whether the reporting of escapes takes into consideration the different rates of pressure in the gas network and how the rate of flow impacts the reporting of the amount of lost gas during an escape, and how this factors into settlement.
- Whether it would be beneficial to consider independent verification of actual leakage against the assumptions in the leakage model.

3 Overview of the shrinkage and leakage model (SLM)

The GB gas infrastructure serves around 21.5 million gas customers, using around 282,000km of pipes.

Section 9.1.a of the Gas Act 1986[i] requires gas transporters to "develop and maintain an efficient and economical pipe-line system for the conveyance of gas" and the Pipeline Safety Regulations 1996 require network operators to ensure that pipelines are "maintained in an efficient state, in efficient working order and in good repair"[ii].

OFGEM define Shrinkage as follows[iii]:

> *"Shrinkage is gas lost from the distribution network through leakage, theft and own use gas (e.g. purging the system during system operations or gas pre-heating prior to pressure reduction). In order to compensate for this unaccounted for gas leaving the system, additional gas to that input by Users has to be purchased by the Gas Distribution Networks (GDNs) and the cost passed onto Users. This process is governed by UNC Section N.*
>
> *GDNs therefore have a UNC responsibility to purchase Local Distribution Zone (LDZ) Shrinkage gas. This shrinkage volume is based on an estimate of likely shrinkage in the forthcoming Gas Year using a variety of assumed system parameters known at the time. At the end of the Gas Year, a shrinkage assessment is made using revised known parameters and the differences reconciled with Users. The GDNs therefore have LDZ Shrinkage volumetric allowances within their price control revenue allowances which limits the shrinkage volumes that they are allowed to pass through to Users. GDNs are thus incentivised to minimise shrinkage. If they incur shrinkage volumes below their shrinkage allowances they retain the value of this over the price control period."*

OFGEM further state:

> *"Shrinkage comprises leakage from pipelines (around 95 per cent of gas losses), theft from the GDN network (c. three per cent), and own-use gas14 (c. two per cent).15 Under the Unified Network Code (UNC), GDNs are responsible for purchasing gas to replace the gas lost through shrinkage, and we fund companies to purchase reasonable levels of gas shrinkage in setting price limits."*

Shrinkage results in a difference in volume between the gas entering the GDN systems and the total volume of gas used by customers. The amount deemed to have been used by customers is the amount entering the GDN (measured by the GDN operator) and the shrinkage. There may be a residual difference between this quantity and the quantity billed to customers by suppliers, this is called "unidentified gas" and outside the scope of this study.

There are three main elements of shrinkage in gas distribution networks (GDNs):

- Leakage (94% of shrinkage) – this forms by far the largest element of shrinkage and can be further split into three high level groups: those from distribution mains, distribution services and above ground installations (AGIs).
- Theft of Gas (4% of shrinkage) – includes situations where, for whatever reason, end users are unaccounted for and are utilising unrecorded gas.

- Own Use Gas (2% of shrinkage) – which relates to gas that is used in the running of the network, particularly gas used for the purposes of preheating at pressure reduction stations.

The overview of the shrinkage elements in Gas Distribution Networks is shown below.

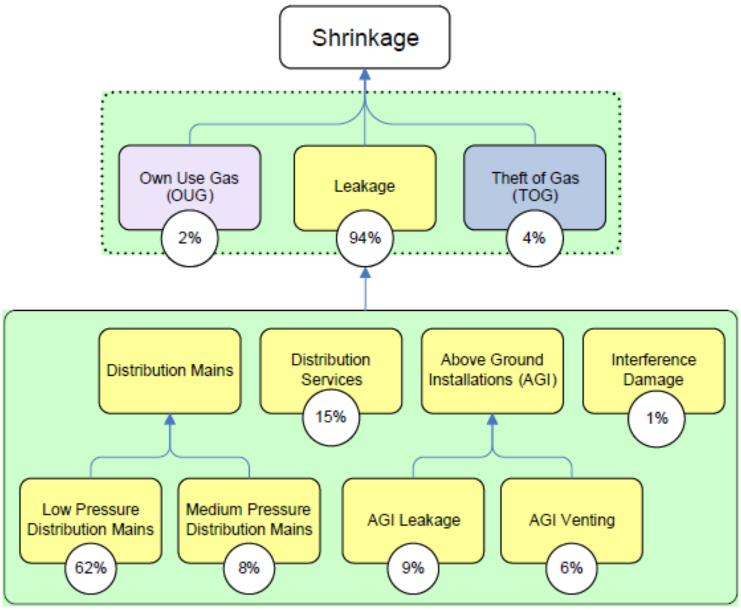


Figure 1. Gas Networks Shrinkage and Leakage Model (SLM) elements (average of 2013-14; all GDNs)

Overall information for the GDNs is provided below, followed by total throughput figures.

	2005-06	2006-07
East of England	49,346	49,409
London	23,373	23,410
North West	34,521	34,550
West Midlands	24,199	24,220
Northern Gas	36,670	36,664
South	49,959	50,036
Scotland	22,982	23,061
Wales and West	34,634	34,696

NGGDD	131,438	131,588
Northern Gas	36,670	36,664
Scotia	72,941	73,097
Wales and West	34,634	34,696

Figure 2. Network lengths (km) per GDN and per group

	2005-06	2006-07
East of England	130,860	127,278
London	68,357	64,882
North West	87,334	84,438
West Midlands	60,117	57,747
Northern Gas	89,422	88,016
South	123,620	118,868
Scotland	61,226	60,603
Wales and West	81,334	80,578
NGGDD	346,668	334,345
Northern Gas	88,300	88,016
Scotia	184,846	179,471
Wales and West	81,334	80,578

Figure 3. Annual throughputs (GWh) per network and group

The figures below indicate the baseline forecasted levels of shrinkage in total by GDN and split out by GDN.

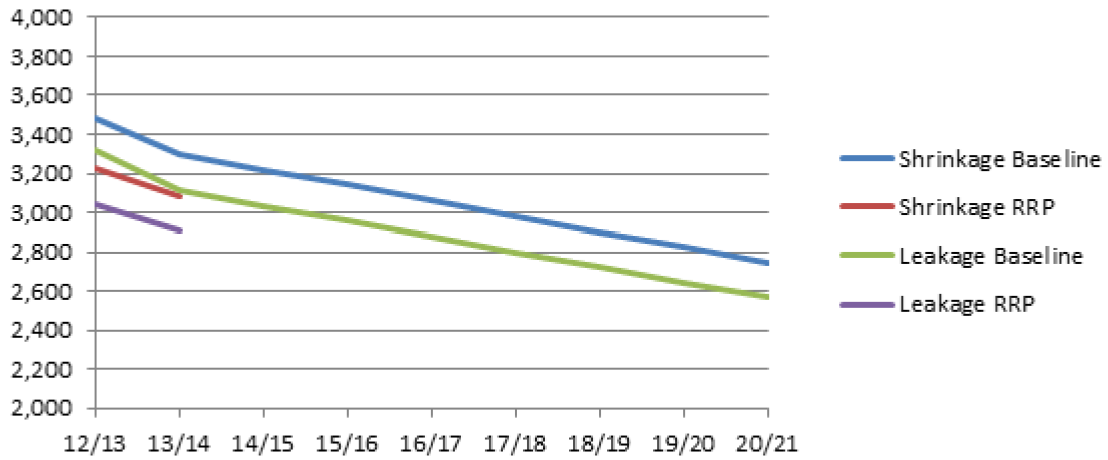


Figure 4. Shrinkage and leakage baseline allowances and actual outcomes (GWh)[lxviii]

The forward allowances are listed below[iv].

Corrected Shrinkage Allowance based on Modification Number Four

Distribution Network	Correct Allowance (£m 2009/10 prices)							
	t=1	t=2	t=3	t=4	t=5	t=6	t=7	t=8
NGGD EoE	11.80	10.80	10.67	10.44	10.24	10.01	9.88	9.68
NGGD Lon	6.10	5.46	5.35	5.23	5.13	5.02	4.83	4.72
NGGD NW	9.00	8.38	8.27	8.05	7.85	7.62	7.42	7.22
NGGD WM	7.00	6.79	6.79	6.59	6.47	6.37	6.27	6.15
Northern Gas Networks Ltd	10.00	9.61	9.39	8.99	8.87	8.77	8.55	8.35
Scotland Gas Networks plc	5.20	4.80	4.70	4.60	4.47	4.37	4.25	4.14
Southern Gas Networks plc	13.30	13.10	13.00	12.68	12.48	12.28	12.06	11.56
Wales & West Utilities Ltd	8.80	8.62	8.62	8.42	8.32	8.22	8.02	7.82

Figure 5. Forward OFGEM Shrinkage Allowances (in financial terms) by GDN[lxviii]

Similarly with the SLM model diagram in Figure 1 above, the joint GDN submission for 2014[v] gives similar figures:

> *"The shrinkage output from the SLM is comprised of three elements:*
>
> • *Leakage (95%)*
>
> • *Theft of Gas (3%)*
>
> • *Own Use Gas (2%)"*

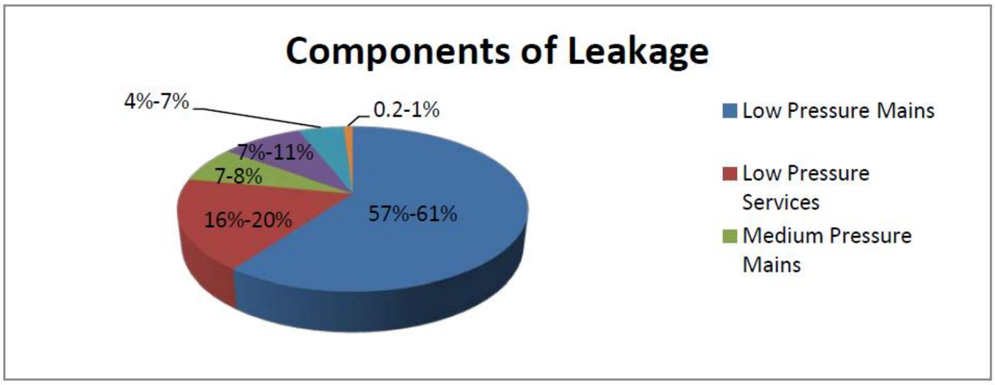


Figure 6. Joint GDN SLM leakage elements

As can be seen, the large majority of the estimated shrinkage is from leakage, which in turn has consequently been the main focus of our report.

The current Shrinkage model has three major components:-

a) Gas lost through transportation (leakage and venting)

b) Own Use Gas (OUG)

c) Theft of Gas (TOG)

Gas lost through transportation is calculated using asset populations, asset attributes, system operating pressures and leakage rates developed through operational research. OUG and TOG are assumed to be a function of throughput, even though it is acknowledged that this is essentially an assumption.

According to Metro[vi]:

> *"Leaks are defined as gas escaping to the atmosphere at a given rate at an unknown location. The rate of gas loss is dependent on the pressure and the size of the hole. Normally, gas leakage will be at a fairly constant rate and will increase gradually with time if not located and repaired."*

Each of the shrinkage elements are reviewed in this document, starting with the leakage model.

3.1 Explanation and review of the leakage model and worked example

3.1.1 Leakage Model and data for Mains

As seen in Figure 6, low pressure mains and services are the largest causes of leaks. Below we first review the mains model and data.

Low pressure mains leakage is defined[vii] as "the gas lost from joints, tapings, corrosion holes and sections of porous main. It does not include releases of gas from broken mains or damaged mains, these are assessed separately".

A national survey carried out in 2002/03 established

- Leakage rates for 11 diameter/material bands
- It considered > 2000 low pressure networks nationally, using these key parameters:
  - Average System Pressure (ASP) is length weighted average of the average pressure in each pipe in the network, which is determined via recorded source pressure data and network analysis
  - MEG Saturation (where used) – determined from recorded data and network analysis
  - Network parameters:
    - For mains: pipe asset lengths by type (note that replacement of metallic mains has the greatest impact)
    - For services: the number (not length) of services by type

Leakage is computed as follows[viii]

- For Ductile Iron, Steel and PE Pipes, leakage rate is:
  - (Rate x Length x ASP)/Reference Pressure (30mbarg) (1)
- For Pit Cast Iron and Spun Cast Iron pipes
  - Split into Lead Yarn (LY) jointed treated by MEG (monoethylene glycol), Lead Yarn jointed not treated by MEG and non-Lead Yarn Jointed
  - Assumption based on historical network analysis 88.5% Pit Cast and 18.5% Spun Cast are Lead Yarn jointed. This gives three elements of the calculation for the leakage rate:
  - For Treated Lead Yarn:
    - [(Rate x Length x LY% x Treated% x ASP)/Reference Pressure] x [MEG Factor/Reference MEG Factor]
  - For Untreated Lead Yarn:
    - [(Rate x Length x LY% x (1-Treated%) x ASP)/Reference Pressure] / [Reference MEG Factor]
  - For non Lead-Yarn jointed
    - (Rate x Length x (1-LY%) x ASP)/Reference Pressure

- Average System Pressure is
  - Determined via Network Analysis

- Demand set at 25% 1 in 20 Peak Six Minute Demand (typical average demand level experienced over the year)
- LP Sources are set at average annual pressure for the purposes of the calculation
- This figure is determined by profiling data, data loggers, clock settings etc.

- (Monoethylene glycol) MEG
  - Monoethylene glycol is used to treat lead yarn jointed mains, which applies to Cast Iron pipes only (Pit and Spun). It is a replacement for the water which was in the original town gas and it is absorbed by the lead yarn, causing it to swell and better fit the joint. The degree of swelling depends on MEG saturation.
  - Saturation is measured throughout the year
  - % of cast iron treated determined using the same network analysis model as used for determining ASP
  - Default cast Iron leakage rates are deemed applicable to a MEG saturation level of 25%, which reflects a 20% reduction in leakage.
    - If less or no MEG is used, leakage rates are uplifted (Fig. 1)
    - if more MEG is used, leakage rates are reduced (Fig. 1)
    - The model user most supply the degree of MEG saturation of the gas
    - We have not found similar MEG related assumptions in other countries; it could be a legacy of the transition from town gas infrastructure.

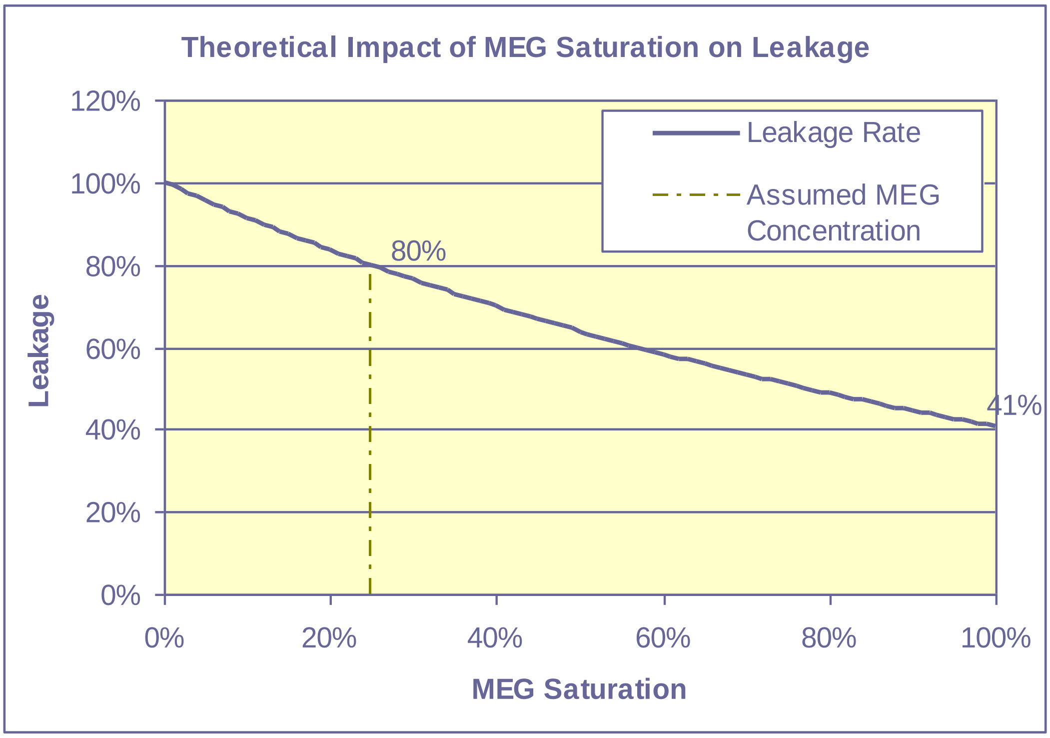


Figure 7. Dependence of Cast Iron leakage versus MEG saturation level

We also note that details on joints are not used in the model.

The overall default leakage rates for mains assumed in the UK SLK model are listed below

m^3/annum/km @30mbarg	D1	D2	D3	D4	D5
MATERIAL	<=3"	4"-5"	6"-7"	8"-11"	>=12"
PE	63.51				
Steel	3416.34	3854.34			
Ductile	719.18		576.40		
Pit Cast	2407.21	1639.85	2525.47	2203.98	7463.40
Spun Cast	1075.71				

Figure 8. Rate of leakage for mains as defined in a national survey carried out in 2002/03

Iron mains

Pit cast grey iron is a brittle material with reasonable tensile strength but very limited elasticity. Natural ground movement, from seasonal changes in soil temperature or moisture, can apply significant forces to a buried pipe, although the extent of overall movement is usually limited in all but landslide conditions. Typically, the ground movement will temporarily distort or deflect a section of the pipe by a few degrees from its original line, which will spring back when soil temperature/moisture returns to its earlier state. However, grey iron pipe will fracture at deflections beyond a few minutes of arc less than 0.1 degree. Ground movement from heavy vehicles produces a similar effect on grey iron mains that are not well supported by the ground below the pipe; forces from wheel loads are less than from soil temperature/moisture change, but are repeated with each vehicle, gradually increasing the pipe deflection until it fractures.

Ground movement and traffic loading are both capable of fracturing pit cast iron pipe in almost all diameters, even when newly laid. If the pipe is subject to surface or pitting corrosion in service, the wall thickness will gradually decrease, reducing the amount of ground movement or loading needed to fracture the pipe.

Relative to pit cast iron pipe, spun iron pipe has a marginally higher tensile strength and slightly thinner wall, giving a similar overall strength and similarly limited elasticity.

Ductile iron is a relatively elastic material, able to withstand substantial deflections and resist all but the most extreme ground movement and surface traffic loads. Ductile iron is also a relatively strong material, with a higher tensile strength than low grades of plain carbon steel. However, the ultimate strength of ductile iron pipe is limited by its wall thickness, which is substantially less than pit or spun cast iron pipe. Ductile iron is still a cast iron material and its overall corrosion rate within any specific soil type is broadly similar to that of pit or spun cast iron. When buried within aggressive soils, all cast irons, including ductile iron, will corrode at an extremely rapid rate.

Grey iron is not an elastic material; grey iron mains will fracture when subject to ground movement arising from normal changes in soil temperature/moisture and/or routine vehicle traffic at the surface. Pipe sizes below 10 to 12 inch diameter fracture readily; larger pipes are more likely to fracture if changes in soil temperature/moisture occur rapidly or when surface loading includes HGV traffic, or when weakened by graphitic corrosion.

The rate of any corrosive reaction will depend principally on the following:

i. Soil temperature
ii. Amount of oxygen available
iii. Inherent corrosivity of the specific soil type
iv. Inherent reactivity of the specific pipe material

Ductile iron mains are likely to have sufficient flexibility to tolerate all but the most extreme ground movement and will rarely fracture in service. For all sizes of ductile iron main, the dominant failure mode is likely to be through wall corrosion. Ductile iron mains below ground will corrode and gradually lose strength; most mains will eventually suffer loss of integrity by some form of perforation. Inevitably, substantially corroded ductile pipe can fracture if subject to significant external loading or ground movement.

The only formal comprehensive review of the Iron Mains Replacement Programme (see section 6.2.3) was carried out by the HSE in 2005. One of the key issues highlighted in the review was that the length of the 'at risk' pipes was significantly higher than estimated in 2001. Transco's 2004 survey found that in 2001 there had been 101,800Km of 'at risk' mains compared to the original estimate of 91,000Km.

Steel Mains

Steel pipe corrodes at broadly similar rates to cast iron pipe and protective coatings applied to steel pipe are similarly prone to damage, usually during transport, storage and pipe laying. However, steel pipe is usually substantially thinner than cast iron pipe of similar diameter, and through wall corrosion will usually occur earlier.

Steel pipe below ground is capable of resisting all but the most extreme ground movement and external loading; the pipe is also prone to corrosion, depending on the aggressive nature of the adjacent soil. In general, steel pipe of all sizes is unlikely to fail in service unless subject to external corrosion. In practice, the protective coatings applied to LP and MP steel mains are prone to damage and corrosion failure in service is not uncommon.

In general, many types of joint used for steel pipe are essentially similar to those used for cast iron mains and joint leaks do occur. However, a substantial majority of small diameter steel mains are screw jointed; overall, steel pipe of all sizes are less likely to leak than cast iron mains.

Wales and the West estimate 460,000 steel or part steel services and, NGG estimate 1.94x10^6 steel services in use in 2010. That suggests that somewhere between 5x106 and 6x10^6 steel or part steel services may be currently in service. Based on WWU data, about 8.0% of total steel services may be connected to steel mains

WWU report an average replacement of 22,700/year, with a total steel population of 460,000. This suggests a replacement rate of about 4.9%. NGG report an estimated 1,942,000 steel services and average replacement rates of 114,000/year, equivalent to 5.9%

Polyethylene (PE)

PE pipe below ground is unaffected by all but the most extreme ground movement and external loading; PE is also noncorrosive and isn't affected by aggressive soils. However, PE can be subject to degradation by chemical attack; PE gas mains within land contaminated with industrial pollutants do occasionally suffer chemical attack in service, but such occurrences are thought to be quite rare. In general, PE gas mains of all sizes/pressures are expected to provide a service life of 50 years or more.

Services

Services are not held on an asset register. The location, material, diameter and age of any individual service is there not known.

In general, if the operating pressure of a gas main is higher, gas will escape at a greater rate. However, there is no clear evidence to show that MP gas mains represent a higher risk than LP mains.

One can see from that Figure 8 and Figure 9 the dependence of the leakage rate for Pit cast mains versus diameter D is highly non monotonic which contradicts physical laws (see section 3.2). We also note that the leakage rates for steel increase with diameter as expected, while they decrease with diameter for ductile which is somewhat unrealistic. The leakage rates for PE and spun cast do not depend on diameter at all, which is again not in accordance with permeation physics. All these inconsistencies are probably the result of limited samples size of materials and networks used in the tests and potentially inaccurate statistical methods applied for processing data.

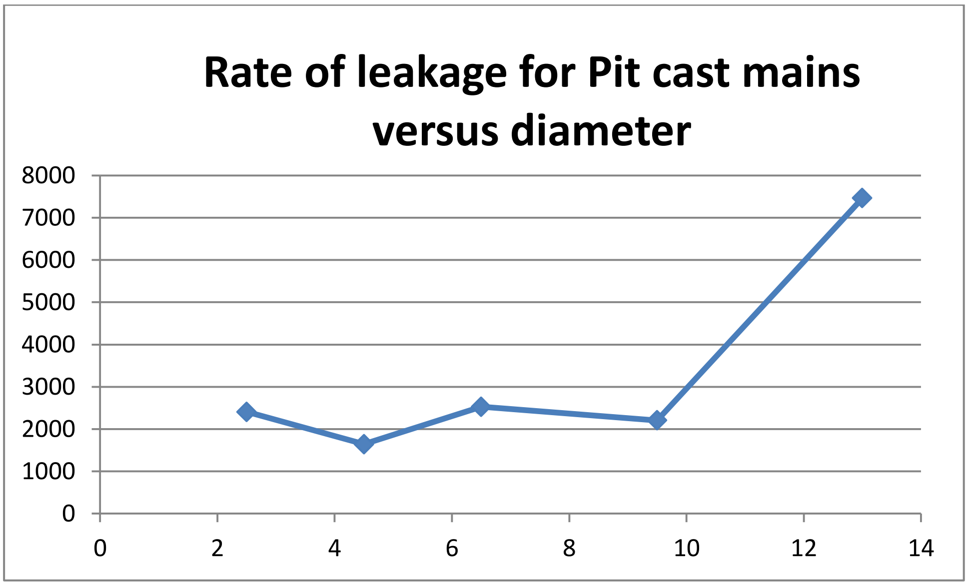


Figure 9. The rate of leakage for Pit cast mains versus diameter D

These inconsistencies all point to the high desirability of conducting a new study; a recommendation that we shall come back to in terms of cost-benefit analysis.

Below a sample leakage calculation is used to clarify the methodology.

3.1.2 Example Leakage Calculation for Mains. Test Case 1

We use assumptions and formulas from the Shrinkage Forum Documentation[viii]

- Test Case 1:
  - <=3" Pit Cast; Original Length = 5.163; Proportion of CI treated = 75%; MEG Saturation = 40%; ASP = 30mbarg
    - Lead Yarn Length (5.163 x 88.5%) = 4.569
    - Lead Yarn Treated Length (4.569 x 75%) = 3.427
    - Lead Yarn Untreated Length (4.569 – 3.427) = 1.142
    - Non Lead Yarn Length (5.163 x (1-88.5%)) = 0.594

  - Lead Yarn Treated Length Leakage =
    - 3.427km
    - x 2407.21 m^3/km/annum@30mbarg [Leakage Rate for D1 Pit Cast]
    - x 30mbarg [ASP]
    - / 30mbarg [Ref Pressure]
    - x 69.78% [MEG Factor Associated with achieved 40% MEG Saturation]
    - / 79.86% [MEG Factor Associated with the reference 25% MEG Saturation]

    =7,208scm

  - Lead Yarn Untreated Length Leakage =
    - 1.142km
    - x 2407.21 m^3/km/annum@30mbarg [Leakage Rate for D1 Pit Cast]
    - x 30mbarg [ASP]
    - / 30mbarg [Ref Pressure]
    - / 79.86% [MEG Factor Associated with the reference 25% MEG Saturation]
    - =3,443scm

  - Non-Lead Yarn Length Leakage =
    - 0.594km
    - x 2407.21 m^3/km/annum@30mbarg [Leakage Rate for D1 Pit Cast]
    - x 30mbarg [ASP]
    - / 30mbarg [Reference Pressure]
    - =1,429scm

Total Leakage = 7,208scm (Lead Yarn Treated Length Leakage)

+ 3,443scm (Lead Yarn Untreated Length Leakage)

+ 1,429scm (Non Lead Yarn Length Leakage)

=12,080 scm/year

3.1.3 Example Leakage Calculation for Mains. Modeling full mains leakage

To model full mains network we need to know the topology (the proportion of various components) of the network. We use the Test Case 1 data and the typical topology from the US EPA data from Figure 10. (Emissions assumptions used by US EPA):

Main-Cast Iron - - 30,904 miles

Main Unprotected Steel 60,633 miles

Main Protected Steel 486,521 miles

Main-Plastic - 674,808 miles

Services Unprotected Steel 3,668 miles

Services Protected Steel- 14,751 miles

Services Plastic - 46,153 miles

Services Copper- 973,107 miles

Then Total Network = Main-Cast Iron + Main Unprotected Steel + Main-Plastic = 766,3 miles

From these data we can fine proportions of various components of the network:

Main-Cast Iron / Total = 4%

Main Unprotected Steel / Total = 8%

Main-Plastic / Total = 88%

Now we can design a test case for the UK mains network using proportions above. From Test Case 1:

Length (3” Pit Cast mains) = 5.163 km, then

Total Length = 129 km
Main Unprotected Steel = 10.3 km
Main-Plastic = 113.6 km

Test Case 2:

Further we use formula (1) to compute

- Main-Plastic Leakage =
  - 113.6 km
  - x 63.51 m^3/km/annum@30mbarg [Leakage Rate for D1 Pit Cast]
  - x 30mbarg [ASP]
  - / 30mbarg [Reference Pressure]
  - = 7,214 scm

- Main- Unprotected Steel Leakage =
  - 10.3 km
  - x 3854.34 m^3/km/annum@30mbarg [Leakage Rate for D1 Pit Cast]
  - x 30mbarg [ASP]
  - / 30mbarg [Reference Pressure]
  - = 39,699.7 scm

Finally, the leakage from the whole network consisting of Main-Cast Iron (Test Case 1), Main Unprotected Steel and Main-PE:

Total Leakage = 7,208scm (Lead Yarn Treated Length Leakage)

+ 3,443scm (Lead Yarn Untreated Length Leakage)

+ 1,429scm (Non Lead Yarn Length Leakage)

+ 7,214 scm (Leakage PE)

+ 39,699.7 scm (Unprotected Steel Leakage)

= 58,963 scm

We can conclude that

1) Leakage from PE (7,214 scm) is comparable with that from 3” Pit Cast Lead (12,080 scm);
2) Leakage from Unprotected Steel is by far the most important contributor to the total leakage (67% of the total leakage)

The above only considers the mains. The other important element of the leakage part of the model is service leakage. This is reviewed later.

We can compare the UK mains and service leakage rates and those of other countries. This is done in overview below, with more explanation in section 4.

3.1.4 Mains and services leakage rates: comparison with other counties

Below is the summary of data from section 4. It indicates that there is a wide variation in leakage rates across countries with similar infrastructure, indicating that the assumed leakage rates are subject to significant uncertainty. The other important point to note is that the UK assumed leakage rates for PE are much lower than those assumed elsewhere; this implies that the expected reductions in leakage from mains replacement may not be as large in practice.

MATERIAL	**UK (** m^3/an/km	**US EPA**	**Netherlands**	**UNFCC assumptions**
Mains –Cast Iron	2407.21 - 7463.4 m^3/an/km 0	4224 m^3/an/km	775 m^3/an/km	5000- 7800 m^3/an/km
Mains-Unprotected steel	3416.34- 3854.34 m^3/an/km	1947 m^3/an/km	No data	No data
Mains-Protected steel	No data	54.33 m^3/an/km	50 m^3/an/km	No data
Mains –PE	63.51 m^3/an/km	175.4 m^3/an/km	210 m^3/an/km	300 m^3/an/km
Services- Unprotected steel	10.6 m^3/an/service leakage	48.13 m^3/an/service leakage	No data	No data
Services- Protected steel	10.6 m^3/an/service leakage	5.09 m^3/an/service leakage	No data	No data
Services- PE	0.0 m^3/an/service leakage	0.28 m^3/an/service leakage	No data	No data

Figure 11. Leakage rates for mains and services. Comparison with other countries: US (EPA), Netherlands and UNFCC (see section 4) for details.

The important message from this comparison is that, given that LP mains leakage is of the order of 60% of all leakage and that the UK uses a relatively low value for the Mains PE leakage rate, there may be an underestimation of leakage in comparison with other international benchmarks. This has implications for both the commercial aspects of system operation and the accounting of national emissions inventories.

There is another important assumption in the mains leakage. This relates to Medium Pressure (MP) Leakage (8% of leakage). The model assumptions state:

> *MP Leakage is estimated by applying the LP leakage rates at 30mbar to the MP mains asset profile. The rationale for this is that the number of public reported escapes (PREs) per km of MP main is of a similar order to that of the LP system and, hence, it is inferred that the mains must be leaking at a similar rate.*

This assumption does not distinguish number of leaks and leak quantity, the physics of leakage (see section 3.2 and Spanish study in section 4.2) indicate that there should be a significant pressure effect. Indeed, our sensitivity analyses below find that ASP is the most important factor in LP mains leakage.

3.1.5 Estimation of Service Leakage

The other major element of the leakage mode is the service leakage element. The service leakage rates established in the 2002 National Leakage Tests were categorised within 4 individual categories based upon the material of the service and the material of the main:

1. Metal service connected to metal main: 10.6m^3/annum/service leakage
2. PE service connected to metal main: 2.2m^3/annum/service leakage
3. Metal service connected to PE main: Zero leakage
4. PE service connected to PE main: Zero leakage

The leakage rates are defined as 'per service' rates and are not dependent upon the individual length of each service. There is no clear substantiation for this assumption.

Estimation of Service Leakage for period 2009 –2012

Following the acceptance and implementation of the revised methodology contained within the 2009 Modification, the service estimation methodology within the leakage model for the period 2009 onwards was amended to include the following additional steps [that would provide improved accuracy in relation to the service leakage estimate from 31st March 2007 onwards] to account for service replacement activity (but not for leakage rates by material).

A] Establish a fixed number of metallic services for each LDZ when the baseline numbers were applicable (i.e. 31st March 2007) based upon the assumption that one third of all services on a mixed material network are metallic.

B] Establish a fixed number of metallic services for each network when the baseline numbers were applicable (i.e. 31st March 2007) based upon the assumption that one third of all services on a mixed material network are metallic.

C] Based upon the number of metallic services replaced within the LDZ since the baseline value was established, calculate the percentage of metallic services replaced for the LDZ for the year.

D] Apply this percentage reduction in services to the fixed metallic service population of each network to determine a revised total of metallic services within each network.

E] Calculate the PE service population for each network by subtracting the value determined in D] from the total number of services within the network.

F] Apply the same assumptions as within the current estimation methodology to determine the service populations within the 4 individual service categories for each network.

Proposed Service Leakage Estimation Methodology

The implementation of the revised methodology for service leakage estimation contained within the 2009 Modification, effectively 'fixed' the number of metallic services assumed at the time the incentive allowances were set in 2006/07 and subtracted from this the cumulative number of services replaced in subsequent years. However, the assumed populations in 2006/07 were themselves based on the relative populations of steel and PE services that existed at the time of the 1992 National Leakage Tests.

The most recent Leakage Model Modification proposes a methodology that is designed to more accurately reflect the service populations within networks.

Service Populations

The proposal to establish current service populations is:

To use the data from 2008/9, 2009/10 and 2010/11 replacement mains lengths, service relays and transfers data to determine the proportion of each type of service connection to metallic mains over this period for each LDZ and to deem this representative of the overall population of service connections to metallic mains for the LDZ. The level of replacement done over a three year period provides a substantial sample of connections, which will lead to a statistically valid estimate of the population; details are provided in Tables 1 and 2.

All service connections to PE mains have zero leakage and therefore the steel/PE service mix of such connections does not matter for leakage derivation purposes. For completeness, it is proposed to utilise data on the mix from the 2002/03 National Leakage Tests (NLT) as outlined in Appendix A. This will establish new values for the four service categories for the base year, which will be 2010/11. For the subsequent years, the population values will be derived from these base year values along with the known

Service Transfers

Following the establishment of new service populations for the base year, 2010/11, the leakage model will have an estimate of the number of services in each of the four categories:

Steel service connections to metallic mains

PE service connections to metallic mains

Steel service connections to PE mains

PE service connections to PE mains

The current model takes account of re-laid services each year by subtracting these from the number of 'steel service connections to metallic mains' category but does not take into account transferred services in a year. There appears no good reason to ignore transferred services. It is proposed, therefore, that the annual updating methodology should include the impact of transferred services; this being achieved by subtracting the number of service transfers from the 'PE service connections to metallic mains' category. The number of service re-lays and transfers will be added to the 'PE service connections to PE mains' category.

Network	length of main replaced (km)	number of relays	number of transfers	Relays/km	Transfers/km
NE	953	45527	32213	48	34
NO	803	35557	25299	44	32

Figure 12. Northern Gas Networks mains replacement data for 2008/9 to 2010/11

Number of tests	Length of main tested	Number of PE services	Number of steel services	Total number of services	PE service %	Steel service %
81	7039	770	14	784	98.214 %	1.786%

Figure 13. Service type connected to PE mains from 2002/03 National Leakage[ix]

There were a number of assumptions within the ‘pre 2009’ leakage model relating to individual network populations of services that enable an estimate of the number of services within the 4 individual service categories to be included within the leakage model. These assumptions were identified as follows:

1. The number of services within a network is deemed to be the same as the number of connected consumers. If possible, this assumption should be checked through the current data cleansing exercise in the industry
2. For an ‘all PE’ mains network, all services are PE
3. For mixed material networks, two thirds of services are PE
4. The number of metallic services attached to PE mains is calculated by multiplying the assumed number of metallic services by 0.187097.
5. PE services are evenly distributed between PE and metallic mains on a length weighted basis.
6. Within the leakage model, the number of services attached to ‘all PE’ networks were identified as ‘excluded services’ and were not included within the subsequent service split calculation.

The service estimation methodology within the leakage model for the period 2009 onwards was amended to include the following additional steps to account for service replacement activity. Leaks are assumed to take place under defined conditions of temperature and pressure.

1. Establish a fixed number of metallic services for each LDZ when the baseline numbers were applicable (i.e. 31st March 2007) based upon the assumption that one third of all services on a mixed material network are metallic.
2. Establish a fixed number of metallic services for each network when the baseline numbers were applicable (i.e. 31st March 2007) based upon the assumption that one third of all services on a mixed material network are metallic.
3. Based upon the number of metallic services replaced within the LDZ since the baseline value was established, calculate the percentage of metallic services replaced for the LDZ for the year.
4. Apply this percentage reduction in services to the fixed metallic service population of each network to determine a revised total of metallic services within each network.
5. Calculate the PE service population for each network by subtracting the value determined in D] from the total number of services within the network.
6. Apply the same assumptions as within the current estimation methodology to determine the service populations within the 4 individual service categories for each network.

3.1.6 Service network leakage: population and leakage factor worked examples.

We consider two different LDZ's, using data published by GDNs

1. **Keswick network in North LDZ (published as part of the review of NGN's SLM[x])**

The data/ assumptions provided are:

Metallic Length = 12.585km;

Total Number Services = 2934

Number Steel Service Connections to Metallic Mains	= Relays/km x Metallic Length = 44.28 x 12.585 =557
Number PE Service Connections to Metallic Mains	= Transfers/km x Metallic Length = 31.506 x 12.585 =397
Total no. service connections to metallic mains	= 557+397 = 954
Total no. service connections to PE mains	= 2934-954 =1980
Number PE service connections to PE mains	= 1980*98.25% = 1945
Number steel service connections to PE mains	= 1980*1.745% = 35

Using these data we can compute:

Total leakage = Service Leakage Rate (Metal service connected to metal main) * Number Steel Service Connections to Metallic Mains + Service Leakage Rate (PE service connected to metal main) * Number PE Service Connections to Metallic Mains = 10.6m^3/annum/service leakage * 557 + 2.2m^3/annum/service leakage * 397 = 5904.2 + 873.4 = 6,777.6 m^3/annum

Emissions assumptions used by US EPA

Using data presented in Section 4 the following leakage rates can be used for estimates:

1. Metal service connected to metal main: 5.09 or 48.13 m^3/annum/service leakage
2. PE service connected to metal main: 0.28 m^3/annum/service leakage
3. Metal service connected to PE main: 5.09 or 48.13 m^3/annum/service
4. PE service connected to PE main: 0.28 m^3/annum/service

In this case, if we just change the PE service assumption to the EPA service rate leakage figure we obtain an increase in leakage of about 10% to 7,439 m^3/annum.

On the other hand, if we assume metallic services are unprotected steel, this would lead to an increase to 29,616, ie over fourfold.

2. The Dundee network in Scotland (SC) LDZ

This data comes from the review of SGN's SLM in June 2012.

Metallic Length = 211.813km;

Total Number Services = 43,708

Number Steel Service Connections to Metallic Mains = Relays/km x Metallic Length

= 44.177 x 211.813 = 9,357

Number PE Service Connections to Metallic Mains = Transfers/km x Metallic Length

= 54.505 x 211.813 = 11,545

Total no. service connections to metallic mains = 9,357+11,545 = 20,902

Total no. service connection to PE mains = 43,708-20,902 = 22,806

Number PE service connections to PE mains = 22,806 x 98.2% = 22,395

Number steel service connections to PE mains = 22,806 x 1.8% = 411

Using these data we can compute
Total leakage = Service Leakage Rate(Metal service connected to metal main) * Number Steel Service Connections to Metallic Mains +
Service Leakage Rate(PE service connected to metal main) * Number PE Service Connections to Metallic Mains = 10.6m^3/annum/service leakage * 9,357
+ 2.2 m3/annum/service leakage * 11,545 = 99,184.42 + 25,399 = 124,583.42 m^3/annum

Using the EPA assumption on PE services would increase this figure to around 134,000.

3.1.7 Uncertainty and sensitivity analysis

Background

Models used to compute leakage are based on uncertain parameters. It is important to quantify how uncertainty in model parameters effects uncertainty the in model output. Global sensitivity analysis (GSA) offers a comprehensive approach to model analysis by quantifying how the uncertainty in model output is apportioned to the uncertainty in model inputs[xi],[xii]. Unlike local sensitivity analysis, GSA estimates the effect of varying a given input (or set of inputs) while all other inputs are varied as well, thus providing a measure of interactions among variables. GSA is used to identify key parameters whose uncertainty most affects the output. This information then can be used to rank variables, fix unessential variables and decrease problem dimensionality. The variance-based method of global sensitivity indices based on Sobol' sensitivity indices became very popular among practitioners due to its efficiency and easiness of interpretation. Annex 3 has more information.

Global sensitivity analysis of the leakage model for Mains

The results for the mains leakage model example is below, where Sobol' sensitivity indices Si are calculated for three different scenarios (S1, S2 and S3). Scenario S3 is the most useful piece of information

X	Name	Value (Xb)	Si (S1)	Si (S1)	Si (S3)
XM1	Leakage Rate of 3" Pit Cast mains	2407.21 m3/km/annum @30mbarg	0.130	0.219	0.0176
XM2	Proportion of CI treated	75%	0.130	0.0147	0.00104
XM3	MEG Saturation*	40%	0	0	0
XM4	Assumption of Pit Cast	88.5%	0.130	0.00	0.0
XM5	MEG Factor Associated with achieved 40% MEG Saturation	69.78%	0.131	0.078	0.00629
XM6	MEG Factor Associated with the reference 25% MEG Saturation	79.86%	0.132	**0.172**	0.0138
XM7	3" Pit Cast mains Length	5.163km	0.131	**0.219**	0.0172
XM8	ASP	30mbarg	0.130	**0.219**	**0.418**
XM9	Main-Plastic Length	113.6 km			0.00625
XM10	Leakage Rate of PE	63.51 m3/km/annum @30mbarg			0.00624
XM11	Unprotected Steel Length	10.3 km			**0.189**
XM12	Leakage Rate of Unprotected Steel (D >= 3")	3854.34 m3/km/annum @30mbarg			**0.189**

Note: * XM3 is not used in the inputs, hence Si(MEG Saturation) is 0

Figure 14. Sensitivity analysis of mains leakage model

Figure 14 presents the base values of parameters XMb and Sobol' sensitivity indices assuming 20% variation in the values of parameters (Xb +/- 10%) for three different scenarios:

S1 – only Lead Yarn Treated Length Leakage is used as output

S2 – all three components of 3'' Pit cast mains (Lead Yarn Treated and Non-Lead Treated) are used as output (Test Case 1)

S3 – total leakage: total leakage: all five components (Lead Yarn Treated and Non-Lead Treated, Steel and PE) are used as output.

Global sensitivity analysis shows that for scenario S1 all parameters are equally important,
for scenario S2 the most important parameters are

1. the Length
2. ASP
3. MEG Factor Associated with the reference 25% MEG Saturation

for scenario S3 the most important parameters are

1. ASP (the highest impact)

2. Unprotected Steel Length
3. Leakage Rate of Unprotected Steel (D >= 3”)

Global sensitivity analysis of the service leakage model

This technique aims to identify the most important parameters/assumptions in the model. These help to prioritise the areas where information is most important.

1. **Keswick network in North LDZ.**

X	Name	Value (Xb)	Si (S1)	Si (S2)	Si (S3)
X1	Metal service connected to metal main	$10.6m^3$/annum/service	0.257	0.259	0.172
X2	PE service connected to metal main	$2.2m^3$/annum/service	0.006277	0.00629	0.00413
X3	Metal service connected to PE main	0	0	0.007	0.0911
X4	PE service connected to PE main	0	0	2.84E-06	3.40E-05
X5	Relays/km	44	0.257	0.235	0.108
X6	Transfers/km	32	0.00587	0.003537	1.04E-05
X7	Metallic Length	12.585km	0.340	0.296	0.108
X8	Total Number Services	2934	0	0.016	0.208
X9	PE service %	98.214 %	0	0.007	0.0911
X10	Steel service %	1.786%	0	2.08E-06	2.63E-05

Figure 15. Sensitivity analysis of service leakage model (Keswick)

Figure 15 presents the base values of parameters Xb and Sobol’ sensitivity indices (the indices which quantify how important the quantity is in the leakage model) assuming 20% variation in the values of parameters (Xb +/- 10%) for three different scenarios:
S1 – all Xb’s are taken from Northern Gas Networks[xiii];
S2 – X2 = X3 = 0.5. m^3, while the rest of Xb’s are unchanged;
S3 – X2 = X3 = 2.2. m^3 (that is they are equal to X2), while the rest of Xb’s are unchanged;

In scenarios S2 and S3 it is assumed that the assumptions that the leakage rates for metal service connected to PE main and PE service connected to PE main are equal to zero are unrealistic. Global sensitivity analysis shows that for all three scenarios the most important parameters are

1. the metallic length
2. the leakage rate for the metal service connected to metal main
3. the number of relays per km

For scenario S3 however, the total number of services becomes an important parameter while the importance of relays/km and metallic length decreases. Surprisingly, even assuming quite high values of the leakage rates for metal service connected to PE main and PE service connected to PE main does not strongly influence the sensitivities of corresponding parameters.

2. The Dundee network in Scotland (SC) LDZ[xiv]

Figure 16 presents the base values of parameters Xb and Sobol' sensitivity indices assuming 20% variation in the values of parameters (Xb +/- 10%). Global sensitivity analysis shows similarly to the previous case the most important parameters are

1. the metallic length
2. the leakage rate for the metal service connected to metal main
3. relays/km

X	Name	Value (Xb)	Si (S1)
X1	Metal service connected to metal main	10.6m^3/annum/service	0.230
X2	PE service connected to metal main	2.2m^3/annum/service	0.0164
X3	Metal service connected to PE main	0	0
X4	PE service connected to PE main	0	0
X5	Relays/km	44	0.230
X6	Transfers/km	32	0.0157
X7	Metallic Length	211.813km	0.367
X8	Total Number Services	43,708	0
X9	PE service %	98.214 %	0
X10	Steel service %	1.786%	0

Figure 16. Sensitivity analysis of service leakage model (Dundee)

3.1.8 Conclusions

1. For all sizes of ductile iron main, the dominant failure mode is likely to be through wall corrosion. When buried within aggressive soils, all cast irons will corrode at an extremely rapid rate. The leakage model does not account for the geography in general and for types of soils, in particular.
2. Steel pipe corrodes at broadly similar rates to cast iron pipe. However, steel pipe is usually substantially thinner than cast iron pipe of similar diameter, and through wall corrosion will usually occur earlier. Steel pipes are prone to corrosion, depending on the aggressive nature of the adjacent soil. Hence types of soils which are not accounted for in the leakage play an important role in estimating leakage rates.
3. PE pipes can be subject to degradation by chemical attack; PE gas mains within land contaminated with industrial pollutants can suffer chemical attack in service which will result in the increased leakage rates.
4. Services are not held on an asset register. The location, material, diameter and age of any individual service is there not known.

5. It follows from the rates of leakage for mains as defined in a national survey carried out in 2002/03 that the dependence of the leakage rates
   A) for Pit cast mains versus pipe diameter are highly non monotonic
   B) decrease with diameter for ductile
   C) for PE and spun cast do not depend on diameter at all

   all of which contradict physical laws. These inconsistencies are the result of limited samples size of materials and networks used in the tests and potentially inaccurate statistical methods applied for processing data.
6. Comparison with other counties show that the UK assumed leakage rates for PE are much lower than those assumed elsewhere. A relatively low value for the Mains PE leakage rate may result in an underestimation of leakage in comparison with other international benchmarks.
7. MP Leakage is estimated by applying the LP leakage rates at 30mbar to the MP mains asset profile. This assumption does not distinguish number of leaks and leak quantity, while the physics of leakage indicates that there should be a significant pressure effect.
8. The service leakage element of the leakage mode contain some assumptions which don't have clear substantiation, f.e. zero leakage rate for metal and PE services connected to PE main, the assumption that one third of all services on a mixed material network are metallic, the assumption that the number of metallic services attached to PE mains is calculated by multiplying the assumed number of metallic services by 0.187097, etc.
9. Leakage from a typical network in one LDZ computed with the US EPA service rate leakage figures for PE gives an increase in leakage up to 10%.
10. Global sensitivity analysis aims to identify the most important parameters/assumptions in the model. These help to prioritise the areas where information is most important.
11. Global sensitivity analysis of the leakage model for mains show that A) for scenario S2 in which all three components of 3'' Pit cast mains (Lead Yarn Treated and Non-Lead Treated) are used as output the most important parameters are the length, ASP, MEG factor associated with the reference 25% MEG Saturation; for scenario S3 all five components of the network are used as output (total leakage) the most important parameters are ASP (the highest impact), unprotected steel length and the leakage rate of unprotected steel (D >= 3”).
12. Global sensitivity analysis of the service leakage model shows that the most important parameters are the metallic length, the leakage rate for the metal service connected to metal main and the number of relays per km.

3.2 Permeation in PE pipelines

As noted above, the leakage model assumes no leakage in PE service pipelines and relatively low (by international standards) leakage in mains. In addition to actual fractures or perforations in a pipeline system, the other ways for gas to leak from a pipeline is via the joint seal and via permeation through the pipe wall. Permeation losses in PE are small, but non-zero and it may be necessary to distinguish between permeation losses and possible leakage. The following equation may be used to determine the volume of a gas that will permeate through PE pipe of a given wall thickness[xv,xvi]:

$$q_P = \frac{K_p A_s \theta P_A}{t'}$$

Where

q_P = volume of gas permeated, cm3 (gas at standard temperature and pressure)

K_P = permeability constant[xvii]

A_s = pipe outside wall area in units of 100 square inches

P_A = pipe internal pressure, atmospheres

Θ = elapsed time, days

t' = wall thickness, mils

Of the above, the major source of uncertainty is the permeability constant, K_P, which is a function of the material of construction of the pipeline. It the case of CH_4 and PE pipeline, K_P is reported to be approximately[xviii] 85 ${cm^3 mil}/{100in^2 atm.day}$. Using this figure we obtain the graph below.

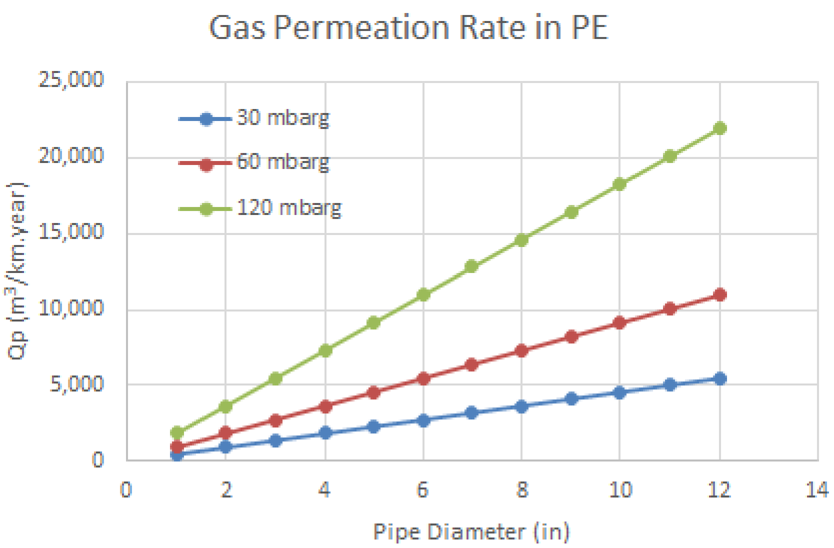


Figure 17: Gas permeation rate through PE pipelines as a function of pipeline diameter and operating pressure, calculated on the basis of a 1 mile length of pipeline.

As is evident from Figure 17, the dominant factor in this relationship is the pressure at which the pipeline is operating. The key result is that a 1 km length of 2" diameter of PE pipeline will leak slightly more than 450 m^3 per year via permeation of CH_4 through the pipeline wall. This is a nontrivial number, relative to those calculated in the previous section (but subject to significant uncertainty as explained below since the K_p = 85 value was probably derived at high pressure). It may therefore be reasonable to suggest that leakage via permeation is an important contributing factor to gas shrinkage; this factor is not included in the GDN model for services at the moment as it is based on the empirical data from the 2002 trial.

Hence, the hypothesis that natural gas (CH_4) does not leak from plastic (PE) service pipelines is incorrect, however it is still likely small (on a per unit length basis) relative to other sources of leakage. However, the data above also indicate a considerable range of uncertainty, all of which relate to rates of permeation. It is important to note that the uncertainty comes from a number of sources

- K_p is actually difficult to measure in a reliable fashion, particularly at low pressures and we suspect the figure of 85 was derived at higher pressures e.g. 4MPa.
- The transport properties of the polymer are a function of the polymer properties, e.g., its crystalinity, void fraction, thermal history – so there is little reason to think that one Kp value is representative of an entire network

We therefore re-evaluate the permeation model using first principles below.

3.2.1 Permeation model

That CH_4 will permeate through PE pipelines is well established in the literature. However, this phenomenon is complex to measure and analyse. Indeed, the permeability (***Pe***), the diffusion (***D***) or the solubility coefficients (***S***) vary generally with many parameters which can be intrinsic to the polymer, such as the weight fraction of crystallinity, the nature of the polymer or even the thermal history of the sample[xix,xx]. The three key parameters, ***Pe***, ***D*** and ***S*** are defined as follows[xxi]:

The permeability coefficient, ***Pe***, expressed in cm^3(STP)/cm·s·MPa, is directly proportional to the rate of gas flow versus the applied pressure and in steady state is written as:

$$Pe = \frac{Ql}{Atp}$$

where ***Q*** is the amount of gas in cm3 (STP), ***l*** is the membrane thickness in cm, ***A*** is the diffusion area in cm^2, ***t*** is the time in s, and ***p*** is the applied pressure in MPa. As is evident from the units used here, the pressure of the gas is an important parameter for a given material.

The diffusion coefficient, ***D***, given in cm2/s, is obtained from the relation:

$$D = \frac{l^2}{6\theta}$$

where $\boldsymbol{\theta}$ is the "time lag" in s. Finally, the solubility coefficient ***S***, expressed in cm^3 (STP)/cm^3.MPa, is calculated as the ratio Pe/D.

For the purposes of this project, we are primarily interested in the calculation of ***Q*** as a function of a measured ***Pe***. This in turn relies on obtaining reliable values of ***Pe***, which can be challenging as the rigorous calibration of the permeation cell is very difficult as far as the expected flow ranged from some tenths of cm^3/h to some cm^3/h. The experimental uncertainties of ***Pe***, ***D*** and ***S***, are of the order of some percent for permeability, from 10% to 15% for the diffusion coefficient and about 20% for solubility.

Further, the precise calculation of the rate of permeation is itself a function of several intrinsic material properties, namely, the degree of crystallinity, $\boldsymbol{X_c}$, and the volume fraction of the crystalline phase, $\boldsymbol{\phi_c}$, both of which also need to be measured, typically via differential scanning calorimetry. For polyethylene, the degree of crystallinity is also an important parameter and an increase of the volume fraction of the amorphous phase ($\boldsymbol{\Phi_a}$) results in an increase of ***Pe***, ***D*** and ***S***.

The following table, reproduced from Flaconnèche et al., gives an indication of the range of values of ***Pe***, ***D*** and ***S*** which would be expected.

Table 1: Transport coefficients of CH_4 in polyethylene

Polymer	T (°C)	p (MPa)	l (mm)	Pe (10^{-7} cm^3(STP)/cm·s·MPa)	D (10^{-7} cm^2/s)	S (cm^3(STP)/cm^3·MPa)
LDPE ($\Phi a = 0.70$)	41	4	1.85	4.3	3.4	1.30
	40	10	1.83	3.7	4.2	0.90
	40	7.5	1.82	4.8	3.7	1.30
	59	7.5	1.80	13	10	1.20
	80	4	1.83	29	23	1.30
	80	10	1.91	28	22	1.30
	77	7	2.75	32	26	1.20
MDPE ($\Phi a = 0.53$)	39	10	2.01	1.2	1.6	0.78
	39	7	1.92	1.5	2.1	0.74
	60	7	1.99	5	4.7	1.10
	59	4	1.95	3.3	6.5	0.51
	80	4	1.91	12	11	1.10
HDPE ($\Phi a = 0.37$)	39	7	2.08	0.92	1.6	0.57
	61	7	1.99	2.6	4.6	0.56
	77	10	2.05	5.1	9.2	0.56
HDPE-R1 ($\Phi a = 0.21$)	41	4	1.84	0.5	1.3	0.39
	41	10	1.69	0.37	1.4	0.27
	60	7.5	1.71	1.2	1.9	0.62
	80	4	1.73	2.3	6.9	0.33
	80	10	1.75	2.4	6.5	0.36

It is further important to note that permeation is also characterised by a time lag – permeation of CH_4 is not instantaneous, and is proportionate to the square of the pipeline thickness (***l***), as illustrated in Figure 18.

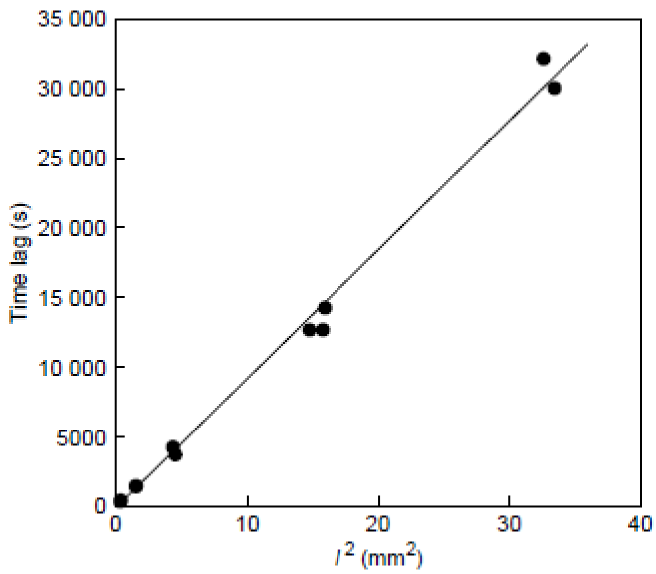


Figure 18: Relationship between time lag and l^2

It is common to compare the speed of the gas molecules to the relaxation speed of the polymer chains that make up the pipeline. Then, the ratio of these speeds allows to separate the various cases of diffusion. The main cases are:

- The relaxation rate of the polymer chains is very high compared to the speed of gas molecules diffusion. Then, the diffusion front propagates at the gas rate in the polymer and the time lag is proportional to the square of the membrane thickness
- In a second case, the diffusion front moves much more slowly than the gas. The time lag is equal to the time necessary for this front to cross the membrane. This time is directly proportional to the thickness.

For example, a PE pipeline with a wall thickness of 5-6 mm is likely to have a time lag on the order of 31,100 s.

Noting that "natural gas" is not, in fact 100% CH_4 but is rather a mixture of alkanes (chain length < 5), it is important to note that the partial pressure of a given component in the gas mixture is more important to the values of the gas transport coefficients, rather than the absolute pressure. Kulkarni and Stern[xxii] studied the permeation of CO_2 and a range of n-alkane gases through PE in a pressure range 0.1 – 4.0 MPa[xxii] and ***S*** appeared independent of pressure, with the diffusion coefficient depending systematically on concentration, and pressures greater than 15 MPa were required to influence ***S***.

Regarding permeability, a study dealt with ten gases from 0.1 to 13 MPa on polyethylene and polypropylene[xxiii]. The authors noted a slight, linear, increase of permeability with the pressure of the most soluble gases, namely CO_2 and CH_4, in PE. On this basis, and using data from Memari et al.[xxiv]

Table 2: permeability coefficients of CH_4 at 298K in PE.

P (MPa)	10^6 Pe_a (cm^3(STP)/cm.s.MPa)
2.9	2.6 ± 1.2

5.0	3.2 ± 0.8
8.4	3.2 ± 0.8

On this basis, we estimate that Pe_{CH4} at ambient conditions to be on the order of 0.5± 0.25 $\times10^{-6}$ cm^3(STP)/cm.s.MPa. This is on the same order as the value of 3.79 $\times10^{-6}$ cm^3(STP)/cm.s.MPa reported by the American Gas Association[xxv].

The ambient temperature is, however, a much more important parameter. Polymers consist of entanglements of macromolecular chains. Increasing the permeation tests temperature leads to a simultaneous increase of the degree of chain mobility and of the gas molecule mobility. This can be expressed via Arrhenius' laws type expressions:

$$Pe = Pe_0 exp\left(\frac{-E_{Pe}}{RT}\right)$$

Where $\boldsymbol{Pe_0}$ is the value reported in Table 2 and $\boldsymbol{E_{Pe}}$ is the activation energy of permeability and has a value in the range 40 – 47 kJ/mol[xxvi]. However, based on the range of temperatures expected to be relevant to gas pipelines in the UK (-5 °C < $\boldsymbol{T_{amb}}$ < 30 °C), temperature is not anticipated to have a first order effect on gas permeation effects, rather the uncertainty in $\boldsymbol{E_{Pe}}$ and $\boldsymbol{Pe_0}$ are significantly more important.

Finally, evaluating the above for a 1 km section of PE pipeline operating at 30 $mbar_g$ over 1 year for pipe diameters between 1 – 12", we obtain the following result:

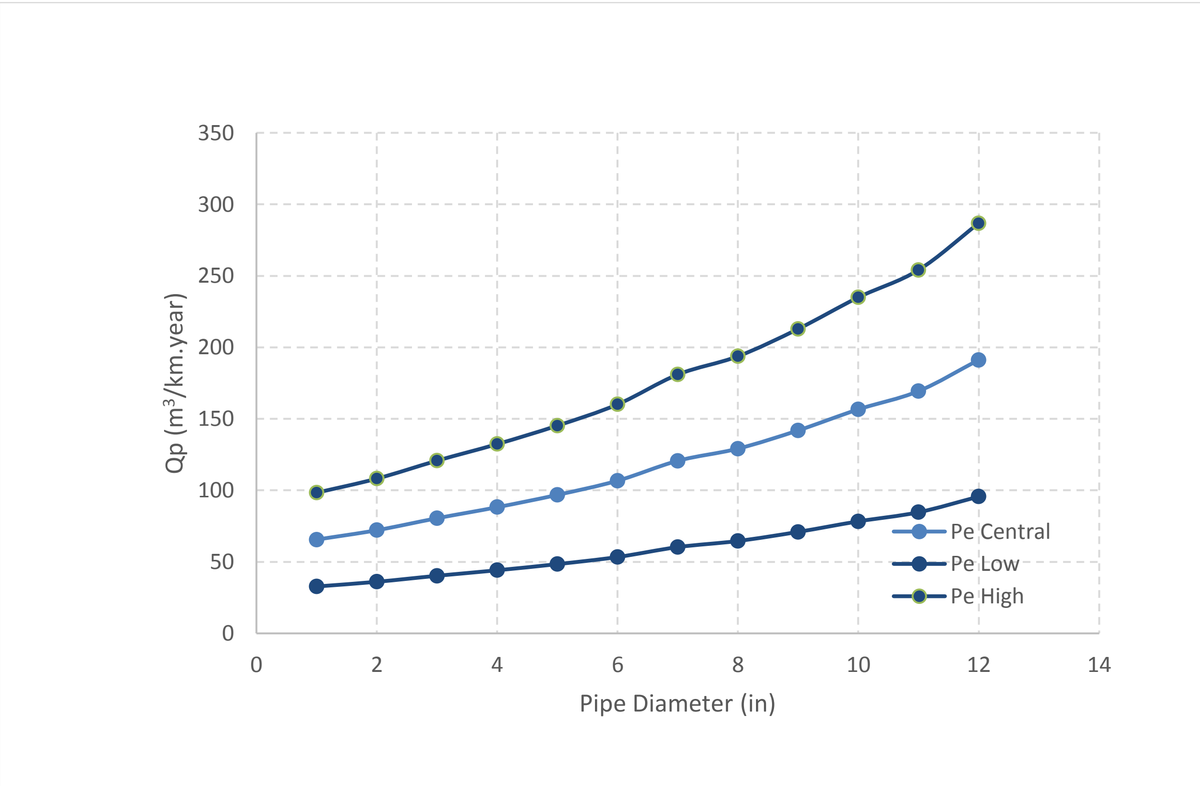


Figure 19: Calculated gas permeation from natural gas pipelines

In line with EN 12201/ANSI/ASME Standard B31.8, the thickness of the pipe wall increases in line with the pipeline diameter. In the absence of detailed information, it was assumed that, as the pipeline diameter increased, so too did the operating pressure, such that at 2”, the line operates at 30 $mbar_g$ but a 12” line operates at 85.6 $mbar_g$. Thus the importance of operating pressure, wall thickness and diameter/surface area are mediated here.

Therefore, a 2” service might be expected to lose 30 – 100 m^3/km.year of CH_4, and a larger main of sya 8” would be expected to lose 129 m^3/km.year. Note that this relate only to permeation in the normal course of operations and does not include additional leakage from e.g. pinholes and joints/seals.

3.3 AGI Leakage

An above ground installation (AGI) is usually where a gas pipeline is brought to ground to facilitate operation and maintenance. They are estimated to be responsible for around 7-11% of leakage. This figure was estimated from a national testing programme in 2002-3, using five different types of AGI and average leakage rates.

To improve the estimation would require a similar survey. The joint GDN submission estimates that this would be expensive (noting that the 2002-3 survey cost around £1m) and argue that an updated survey would not be cost effective at the moment.

They do note that new technologies for identifying leaks and measuring leakage rates are being developed; these could bring down costs of a new survey and so developments in this area should be monitored.

There is not much literature on gas leakage rates from AGIs, but it was noted that up to 2% of all gas entering the GDN was leaking from Titas Gas Networks in Bangladesh.

We also note that the AGIs are not distinguished by age in the leakage model; this would be good practice as performed in the oil and gas industry where an age factor is used to modify “nominal” leakage rates.

As explained in section 5.2.1, the emissions factor increases with age; the standard factors are multiplied by age factors as follows:

Commissioning data	**Age adjustment factor**
After 1988	1.0
Between 1980 and 1988	1.3
Before 1980	1.5

3.4 AGI Venting

AGI Venting is estimated to account for 4%-7% of leakage

GDNs use pneumatic control systems to control pressures at a number of large pressure reduction sites. These systems use the onsite natural gas, which is therefore routinely vented during normal system operation. The control systems have two relevant elements:

- Positioners which adjust the regulator to meet the required pressure following signals from Controllers
- Controllers which monitor pressures and send signals to the Positioners

These can be separate pieces of equipment or a single piece of equipment that operate as both.

The venting of gas that comes about through these operations is estimated based on a national figure quoted in a Watt Committee report from 1994. Today, the derivation of this value is unknown and as it is a single fixed value for each LDZ, it remains unchanged and it is difficult to refine without knowing the assumptions and basis of the calculation.

As a result, GDNs have initiated site surveys in support of a project raised by National Grid to review venting rates of the most common pieces of equipment used to pneumatically control AGIs. The aim is to improve the AGI venting estimation by making it an activity based calculation.

For example, NG is undertaking studies[xxvii] at the North West and West Midlands and the Eastern, East Midlands and North Thames networks. The results should be reported in late 2015.

It was expected that a revision to the AGI Venting calculation, based on the outcome of the study, would have been subject to a formal consultation later in 2014/15. However, the outcome from the initial surveys has indicated that further survey work is required and formal consultation is not now expected until late 2015 at the earliest.

It would make sense to await the outcomes of these trials and consultations, since the original venting estimation method is clearly very approximate. As explained below, there are various strands of work underway to improve AGI venting estimates, and would make more sense to review these improved estimates which take account of evidence on the ground.

The GDNs are required to perform an annual review of the shrinkage and leakage model (SLM).

The outcome of the GDN's 2014/15 SLM review[xxviii] with review to AGIs is:

> *GDNs have initiated site surveys in support of the proposed modification consultation initiated by National Grid in respect of Above Ground Installations*

The AGI plans are illustrated below.

AGI Leakage	N	No development of SLM planned although GDNs will continue to evaluate new technologies and the potential for updating leakage rates
AGI Venting	Y	GDNs have initiated site surveys to review venting rates of the most common pieces of equipment used to pneumatically control AGIs. The aim is to improve the AGI venting estimation by making it an activity based calculation

Further details are below:

Proposed Above Ground Installation Venting Model Modification

Currently, the leakage model assumes a fixed level of venting from Above Ground Installations. This level is that quoted in a 1994 Watt Committee report; however, the quoted value is single value for the UK and its derivation is unknown. The leakage model allocates this value across the thirteen LDZs based on the number of AGIs that typically have routinely venting equipment. As the derivation of the AGI Venting estimate is unknown, this remains unchanged in the leakage model each year.

It is proposed that site-specific data be used to estimate the amount of AGI venting for each LDZ. The advantages of this are that the estimate would be reflective of current equipment in each LDZ and would have a known derivation. The venting estimate would be 'activity' based, i.e. it would be linked to specific equipment, and as such, it would be possible to reflect changes associated with any replacement activity.

However, steady-state venting is not the only venting that takes place at AGIs. Equipment that routinely vents also has additional venting when physically controlling actuator movement. The associated level of this venting is very difficult to determine as it depends on the number of control actions taking place. It is proposed that a 25% uplift to steady-state venting be applied to account for this; however, given that this is only an arbitrary value, it is considered that this volume should not form part of the incentive. Therefore, this level of venting could either be included as a fixed element within the leakage model or simply omitted.

The proposed AGI Venting calculation is shown in detail in Appendix B.3 (reproduced below)

It is the Proposers' view that this is a better methodology for estimating steady-state AGI Venting leakage that improves the accurate calculation of leakage in accordance with Special Condition E9 paragraph 4(a).

B.3 Proposed methodology for determining AGI Venting leakage

There are two pieces of equipment at AGIs that typically vent gas under steady-state conditions, Positioners and Controllers. These pieces of equipment are designed to work with compressed air; however, they were adapted to work with compressed gas, as this was readily available on site. Each AGI has a number of Positioners and Controllers and there are usually more Controllers than Positioners.

Annual Venting Rate is calculated as:

$$\dot{V} = \frac{\dot{v}_{ss}}{35.366} \times \frac{P_{Act}}{P_{ref}} \times 60 \times 24 \times 365 \times N$$

Where

$\dot{V}$ is the total annual venting rate for the equipment type at the AGI

$\dot{v}_{ss}$ is the steady - state venting rate for the equipment type in scf/min

35.366 is the conversion from scf to scm

P_{Act} is the actual operating pressure of the control system

P_{ref} is the specified operating pressure at which the quoted venting rate is applicable

N is the number of units of the equipment type at the AGI

A typical calculation is shown below. Venting rates are quoted at a specified operating pressure. The pneumatic control systems at AGIs tend to operate at 70psi and a linear relationship is assumed for venting.

Equipment Type	Steady-state venting rate (scf/min)	Specified operating pressure (psi)	Mean operating pressure (psi)	Venting rate per device (scm/day)	Number of units on site	Annual venting rate (scm/yr)	25% uplift for non steady-state conditions (scm/yr/site)
Positioners	0.20	20	70	28.5	5	52,016	65,020
Controllers	0.05	20	70	7.1	9	23,407	29,259
					Total	75,423	94,279

3.5 Own use of gas

"Own use of gas" (OUG) refers to gas used by the transporter for operational purposes, which is mainly for preheating, but which does not pass through a meter.

Because the amount is not metered, the quantity is currently estimated by applying a fixed 0.0113% factor to throughput, which was established by a study carried out in 2002. This definition was formally approved by the Authority on 16 September 2014. From the SLM review document[xxix]:

Own Use Gas (OUG) – This is currently measured as a percentage of annual through-put with no direct reduction commitment. The majority of the GDNs' OUG is linked to the requirement to pre-heat gas entering their systems from the NTS. The GDNs' preheating requirements are currently delivered via aging Water Bath Heaters or more modern Boiler Package Technologies. However, there are several key issues that GDNs currently face when appraising options for preheating technologies:

- *the whole life costs and, in particular, the carbon impact of currently available technologies is not understood; and*
- *secondly there has been limited research and development in this area resulting in limited financially viable alternatives to existing technologies.*

Ofgem awarded funding for a Network Innovation Competition project to investigate the options for modernising gas preheaters in a low carbon environment (more information on this project is available in the innovation section below).

Prior to pressure reduction points in the system, preheating is required to ensure that the subsequent temperature is not too low. This is usually performed in a water bath preheater, as in the picture below.

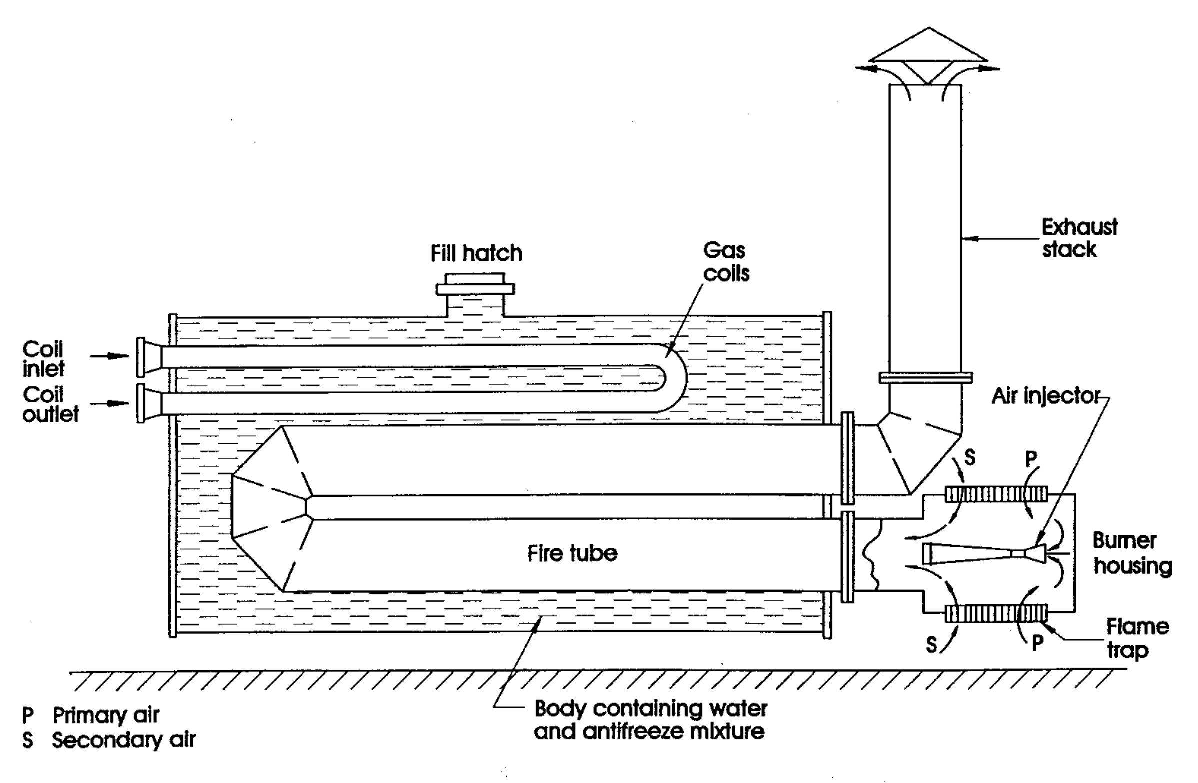


Figure 20. Water bath preheater for GDNs[xxx]

Advantica reviewed the model again in 2006[xxx]; they found that there were large uncertainties in each system due to the low level of data and metering. Particular uncertainties include:

- Pre-heater efficiencies
- Control regime of pre-heaters
- Ground temperature assumptions
- Scaling factor to estimate pre-heater consumptions for LDZs with missing data

Their study gives rise to ranges as follows

- 95% confidence intervals attributed to missing data
    - 0.0102% (assuming a heater efficiency of 50%).
    - 0.0137% (assuming a heater efficiency of 50%).
- Including variation in efficiency of the pre-heaters, the actual OUG percentage figure may lie between:
    - 0.0073% (with 70% efficiency)
    - 0.0229% (with 30% efficiency)

This indicates that own use gas could be anywhere from around 60% of the current estimate to just over 200% of the current estimate. If the latter estimate were right, then we would expect around 2% additional shrinkage.

We note that Northern Gas Networks are currently undertaking a network innovation project investigating Low Carbon Gas Preheating[xxxi] which involves installing and monitoring the operational efficiency of a representative sample of preheating technologies. It was anticipated that by December 2014 live data from 8 sites with different pre-heater technologies will be available. This will allow a comparison of the system efficiency of each site/technology to be undertaken.

We expect data from this project will be at some point be made public due to the funding regime and strongly recommend a data request which can be used to provide new estimates. The data are also starting to be published[xxxii].

3.6 Theft

The theft element in shrinkage is only the 'transporter responsible' theft. Theft is very difficult to quantify exactly so it has ended up being a negotiated proportion of LDZ throughput. The calculation is as follows:

Instances of Theft are assumed to be 0.3% of LDZ throughput, of which 10% of the total theft is transporter responsibility (i.e. 0.03% of LDZ throughput).

Note that "Transporters however believe that only 3.1% is transporter responsibility (i.e. 0.01% of LDZ throughput) based on confirmed occurrences of theft from xoserve"

Theft upstream of emergency control values (ECVs) – which is the responsibility of the transporters- has proven to be difficult to identify so is currently agreed to be 0.02% of LDZ throughput.

According the joint GDN SLM submission, all of the GDNs recognise the potential for customers to be taking unmetered gas from their networks and have set up dedicated teams within their businesses to address the issue.

The GDNs have developed a Theft of Gas Code of Practice managed by the Supply Point Administration Agreement and claim to have developed a clear set of guidance for industry parties on how to approach theft of gas investigations.

They claim that:

> *"These efforts have been focused on ensuring robust processes are in place to resolve cases of illegally taken gas (through physical tampering upstream of the ECV or through lack of supply contract), substantially reducing the number of outstanding shipperless and unregistered sites as well as implementing measures to prevent new shipperless/unregistered site creation.*
>
> *In addressing the outstanding workload of shipperless/unregistered sites on behalf of industry GDNs implemented a project led by Xoserve which during 2014 sent letters and then commenced site visits to almost 23,000 sites nationally. When GDNs reported back to Ofgem in October 2014, 38% of these sites had been cleared either through data cleansing or supplier registration and work is still on-going.*
>
> *In order to reduce the number of newly created shipperless/unregistered sites several measures have been implemented by GDNs and industry including Uniform Network Code and MAMCoP modifications, amended industry processes and enhanced customer communications. All of these measures combined should greatly reduce the likelihood of new sites taking gas without a supply contract."*

3.7 Interference damage

This is the final element of the SLM estimate. The amount estimated is small, under 0.5% of all leakage. It is based on

1. the recording of large release incidents of over 500kg, and the amount is calculated as follows:

- Actual release value where recorded/estimated
- Else, number of incidents x 500kg (i.e each incident is assumed to leak 500kg)

2. Plus the number of other recorded incidents, which are estimated to be:
    a. Split by LP/MP (95/5)
    b. Split by Puncture/Fracture (50/50)

   And with assumed leakage rates and response/fix times which are fixed within the model as follows:

- Severed Services
    - Number of Service Incidents/2 x Rate (17m^3/hr) x Response/fix time (2hr)
- Punctured Services
    - Number of Service Incidents/2 x Rate (5.66m^3/hr) x Response/fix time (2hr)
- Service leakage rates determined for by an experimental rig operating at 25mbarg
- Low Pressure Incidents
    - Number of Mains Incidents x 95% x Rate (42.45m^3/hr) x response/fix time (235 minutes)
- Medium Pressure Incidents
    - Number of Mains Incidents x 5% x Rate (283m^3/hr) x response/fix time (235 minutes)
- Where the mains leakage rates calculated for a 1” hole at 25mbarg operating pressure for LP and 2barg for MP
-

The one element to query in this model is why 500kg is used as the assumed release when the release is not recorded.

3.8 Imbalance caused by Calorific Value (CV) dependence on actual temperature and pressure

The amount of gas which enters the GDN is usually characterised by Calorific Value (CV).

The CV refers to the amount of energy released when a known volume of gas is completely combusted under specified conditions. The CV of gas, which is dry, gross and measured at standard conditions of temperature (15^{o}C) and pressure (1013.25 millibars), is usually quoted in Megajoules per cubic metre (MJ/m^3). Gas passing through the National Grid pipeline system has a CV of 37.5 MJ/m^3 to 43.0 MJ/m^3[xxxiii]. The same convention is used for conversion from the volumetric to CV of gas shrinkage. A daily CV average for each charging area is provided by National Grid to the gas shippers and suppliers. Assumptions of the standard conditions can gives rise to an imbalance caused by the discrepancy between standard and actual P,T at the leakage point. In particular, during colder periods of higher consumption, it might be expected that total leakage will be higher. Furthermore, the gas is likely to be at temperature conditions below the standard conditions. As noted above, the leakage rates are computed on a volumetric basis (m3 per unit time). When the amount of leakage is converted to a total calorific value of leakage, if the leak temperature is lower than standard temperature, the number of moles of gas leaked will be higher than the amount predicted by the standard CV. This means that there is an effective “CV shrinkage” at the leak point. This is quantified below.

Physical model. Assumed temperature and pressure

The standard conditions assume a constant gas temperature of 15^{o}C and a gas pressure of 1013.25 millibars at Mains and Services. However gas temperature and pressure at Mains and Services varies with time. This effect on the actual gas shrinkage volume and CV can be understood via the equation for an ideal gas. Further we will use the following notations:

P_r – the assumed pressure: P_r = 1013.25 mbar

T_r – the assumed temperature: T_r = 288.15 K (15 C)

V_r – the resulted volume of gas at P_r and T_r

$P_a(t)$ – the actual pressure at Mains or Services

$T_a(t)$ – the actual temperature at Mains or Services

V_a – the actual volume of gas at at Mains or Services $P_a(t)$ and $T_a(t)$

From the equation for an ideal gas

$$\frac{P_r V_r}{T_r} = \frac{P_a V_a}{T_a} \qquad (1)$$

we find that

$$V_r = \frac{P_a T_r}{T_a P_r} V_a \quad (2)$$

Then the imbalance between the assumed and actual gas volume is equal to $V_a - V_r = (1 - \frac{P_a T_r}{T_a P_r}) V_a$. The relative (normalized by V_a) imbalance is given by (3):

$$I(T(t), P(t)) = \frac{V_a - V_r}{V_a} = (1 - \frac{P_a T_r}{T_a P_r}) \quad (3)$$

This imbalance can be quite significant. F.e., in winter time assuming $T_a(t)$ = 0 C (273.15 K), $I(T(t), P(t))$ = - 5.5% (further we assume that P_r is close to $P_a(t)$). Generally,

1) in winter when $T_a(t)$ < T_r the relative imbalance is negative. It means that the reported CV shrinkage of gas (if the volumetric shrinkage of gas would have been known precisely) is larger than the actual shrinkage due to the assumptions of the standard conditions.
2) in summer when $T_a(t)$ > T_r the relative imbalance is positive. It means that the reported CV shrinkage of gas (if the volumetric shrinkage of gas would have been known precisely) is smaller than actual shrinkage due to the assumptions of the standard conditions.

The actual temperature and pressure of the gas at Mains or Services are strongly affected by the length of pipeline below the ground, pipeline diameter, material of pipeline, type of soil, location, the gas flowrate, and local temperature and pressure. While the local temperature and pressure can be provided by weather stations at each LDZ, the values of other parameters may not be known precisely.

To estimate the averaged annual relative imbalance, a daily imbalance must be weighted by gas consumption. Obviously, in winter when the largest shares of gas are consumed these weights will be larger than in summer. It will result in a negative overall averaged annual relative imbalance. However, accurate simulation knowing all above mentioned data is needed to predict the actual value of averaged annual relative imbalance.

3.9 Key findings on leakage model

The sections above have identified a number of important findings which are summarised here:

1. The shrinkage and leakage model is based on a combination of experimental data from a leakage study over 12 years ago and assumptions around other model elements.
2. Because of its empirical nature, the leakage element has some features which are not supported by theory (e.g. diameter independent leakage rates, high figures for steel than iron).
3. The leakage rate for LP mains (60% of shrinkage) is significantly lower than that used in other countries and by the UN. It is also lower than our central permeation estimate [63 versus 109] which does not include leaks from holes/joints/seals.
4. PE services are assumed to have a leakage rate of zero which is unlikely in practice. Our estimate and US one.
5. The network composition data requires a number of assumptions to evaluate the distribution of material types; the data that underpins this is hard to find.
6. AGIs do not use an age adjustment factor for leakage; there are some ongoing studies on venting which may improve model accuracy.
7. Preheating is not metered and subject to significant uncertainty; again the use of gas will depend on the age of the facility. An innovation trial should be monitored. The possibility of metering could also be explored
8. The shrinkage estimate may be influenced by a few percent through CV shrinkage, due to the lower temperatures prevailing at times of high gas consumption.
9. If orifice plates are used to meter LDZ entry, they may under-report under low flow conditions.
10. The most significant elements in the model will relate to:
    - 10.1. LP mains leakage rates
    - 10.2. Network composition
    - 10.3. Assumptions on service leakage rates

Overall, it is our view that a new study utilising the latest detection and measurement technologies would be worth performing. Although the cost might be of the order of £10m, when compared to the uncertainty of the shrinkage measures the figure is not large. For example, it could easily be argued that the shrinkage estimate error is at least 20% which is of the order of £15m p.a. (based on an approximate total shrinkage value of £75m), hence the uncertainty resolution cost is very low compared to the level of uncertainty. We expect that emerging technologies (non-invasive or minimally invasive) for leak detection and magnitude estimation could reduce this cost significantly.

Furthermore, this is important for the National Emissions Inventory which must be reported by DEFRA every year. It will not be made redundant by smart meters, since these may be able to evaluate shrinkage more accurately but not apportion it and hence not lead to actionable data. The new study would therefore be future proof.

4 Other evidence in the international literature: leakage estimates, measurements and policies

4.1 Leakage estimation methodologies

Most countries follow an estimation method similar to that of the UK whereby there are three key elements:

- Description of activity level
- Description of infrastructure type
- Emission ("leakage" factors)

In addition their usefulness in commercial reconciliation and regulation, they have needed to be developed for GHG emissions reporting as part of national inventories, given that methane is a potent GHG. Normally the latter are reconciled with the commercial GDN operators' estimates, as in the UK national emissions inventory.

An example of the emissions factors are those from the US; the latest figures are below:

Table A-138: 2013 Data and CH_4 Emissions (Mg) for the Natural Gas Distribution Stage

Activity	2013 EPA Inventory Values				
	Activity Data		Emission Factor (Potential)[aa]		Calculated Potential Emissions (Mg)
Pipeline Leaks					
Mains—Cast Iron	30,904	miles[a,1]	238.70	Mscf/mile-yr[b]	142,076.9
Mains—Unprotected steel	60,633	miles[a,1]	110.19	Mscf/mile-yr[b]	128,678.8
Mains—Protected steel	486,521	miles[a,1]	3.07	Mscf/mile-yr[b]	28,738.1
Mains—Plastic	674,808	miles[a,1]	9.91	Mscf/mile-yr[c]	128,798.3
Services—Unprotected steel	3,668,842	services[a,1]	1.70	Mscf/service[b]	120,179.5
Services Protected steel	14,751,424	services[a,1]	0.18	Mscf/service[b]	50,144.6
Services—Plastic	46,153,036	services[a,1]	0.01	Mscf/service[b]	8,265.2
Services—Copper	973,107	services[a,1]	0.25	Mscf/service[b]	4,766.6
Meter/Regulator (City Gates)					
M&R >300	4,095	stations[d,2]	179.80	scfh/station[b]	124,235.7
M&R 100-300	14,946	stations[d,2]	95.60	scfh/station[b]	241,063.4
M&R <100	7,988	stations[d,2]	4.31	scfh/station[b]	5,809.0
Reg >300	4,478	stations[d,2]	161.90	scfh/station[b]	122,305.5
R-Vault >300	2,630	stations[d,2]	1.30	scfh/station[b]	576.8
Reg 100-300	13,545	stations[d,2]	40.50	scfh/station[b]	92,556.1
R-Vault 100-300	6,086	stations[d,2]	0.18	scfh/station[b]	184.8
Reg 40-100	40,648	stations[d,2]	1.04	scfh/station[b]	7,132.3
R-Vault 40-100	36,046	stations[d,2]	0.09	scfh/station[b]	526.1
Reg <40	17,236	stations[d,2]	0.13	scfh/station[b]	386.8
Customer Meters					
Residential	42,192,085	Outdoor meters[b,2]	143.27	scfy/meter[b]	116,424.6
Commercial/Industry	4,797,283	meters[b,2]	47.90	scfy/meter[b]	4,425.8
Routine Maintenance					
Pressure Relief Valve Releases	1,252,866	milemain[a,1]	0.05	Mscf/mile[b]	1,206.5
Pipeline Blowdown	1,366,993	miles[b,2]	0.10	Mscfy/mile[b]	2,685.5
Upsets					
Mishaps (Dig-ins)	1,366,993	miles[b,2]	1.59	Mscfy/mile[b]	41,862.0
Regulatory Reductions (kt)					-
Voluntary Reductions (kt)					(40.5)
Total Reductions (kt)					**(40.5)**
Total Potential Emissions (kt)					**1,373.0**
Total Net Emissions (kt)					**1,332.5**

[a] Pipeline and Hazardous Materials Safety Administration (PHMSA), Office of Pipeline Safety (OPS) (2013)
[b] EPA/GRI (1996), Methane Emissions from the Natural Gas Industry
[c] ICF (2005), Plastic Pipe Emission Factors
[d] ICF (2008), Natural Gas Model Activity Factor Basis Change
[aa] Emission factors listed in this table are for potential emissions (unless otherwise indicated in a footnote). For many of these sources, emission reductions are subtracted from potential emissions to calculate net emissions. For this reason, emission factors presented in these tables cannot be used to directly estimate net emissions from these sources. See detailed explanation of methodology above.
[1] Activity data for 2013 available from source.
[2] Ratios relating other factors for which activity data are available.

Figure 21. Emissions assumptions used by US EPA[xxxiv]

Note that the leakage rates for plastic infrastructure are non-zero; the model even includes leakage rates for plastic services. The figure for plastic mains (averaged across all pressures and diameters) is equivalent to 175 m^3/km-year

These data are used to make comparisons with the UK GDN SLM assumptions:

- LP PE mains leakage rate: 175 m3/year (USA) versus 65.31 (UK)
- 5m^3/annum/service for protected steel (USA)/ 48.1 for unprotected versus 10.6 (UK)0.28 m^3 per PE service (USA) versus 0 in the UK

The US also has a different set of factors, the so-called GHGRP Subpart W factors, reproduced below from[xxxv].

PIPE USE	MATERIAL	EPA/GRI (1996)[92]		EPA GHG INVENTORIES (2009; 2014)[93]		GHGRP SUBPART W TABLE W-7[94]	
Main	Unprotected Steel	51,802	scf/leak-yr	110.19	Mscf/mile-yr	12.58	scf/mile-hr
	Protected Steel	20,270	scf/leak-yr	3.07	Mscf/mile-yr	0.35	scf/mile-hr
	Plastic	99,845	scf/leak-yr	9.91	Mscf/mile-yr	1.13	scf/mile-hr
	Cast Iron	238,736	scf/mile-yr	238.70	Mscf/mile-yr	27.25	scf/mile-hr
Service	Unprotected Steel	20,204	scf/leak-yr	1.70	Mscf/serv.-yr	0.19	scf/serv.-hr
	Protected Steel	9,196	scf/leak-yr	0.18	Mscf/serv.-yr	0.02	scf/serv.-hr
	Plastic	2,386	scf/leak-yr	0.01	Mscf/serv.-yr	0.001	scf/serv.-hr
	Copper	7,684	scf/leak-yr	0.25	Mscf/serv.-yr	0.03	scf/serv.-hr

Figure 22. GHGRP Subpart W emissions factors

These factors equate to a mains plastic leakage rate of around 173 m^3/km-year and 0.25m^3/service-year.

These can be compared with the system in Spain, which is described by Barroso et al.[xxxvi], who state that steel MP mains leakage factors went from 5 to 1 Nm3/m and PE MP mains from 1 to 0.46 Nm3/m following experimental investigations. They summarised the assumptions of other bodies in the table below. They also state that

"In the European Union about 80% of the methane emitted to the atmosphere is attributed to natural gas released from the distribution systems (IGU, 2000). According to (Eurogas-Marcogaz, 2003), these losses include: fugitive emissions (small and more or less continuous leaks from the flanges, valves and other elements of the network), pneumatic emissions in valves and gas vented due to maintenance works or incidents. In general, gas losses are not measured directly but are estimated according to the various methodologies available. Such estimates are known to involve large uncertainties and further work is needed to improve their reliability".

Emission factors for polyethylene mains.

Methodology	Source	FE (Nm^3/year/m)
E-M	Eurogas-Marcogaz, 2003	0.47
IPCC	IPCC (Shorter et al., 1996)	1.10
IGU	IGU (IGU, 2000)	1.00
Fraunhofer	Eurogas-Marcogaz, 2003	0.33
Lott	Lott (Rose, 1994)	0.06
BG	Rose (Lamb et al., 1995)	0.38
Average	Average from the preceding methodologies	0.55
Spain: PGM	Gas Natural SDG (Lott, 1994)	1.00
Spain: Measured	Average of 2005 and 2007 Spanish, and 2007 Mexican campaigns	0.46

Figure 23. Summary of PE mains emissions factors assumptions used by various bodies

The UN also requires estimates of leakage (emissions) for its Clean Development Mechanism (CDM) which encourages investments which reduce the emissions of GHGs. It has developed such factors for iron and PE, the point being to estimate the benefit of switches in mains. These are summarised below.

Iron

The baseline emissions factor for leaks of natural gas in a low pressure distribution network (less than 50 mbar) with cast iron pipes mains and services (EFOP) is calculated in this methodology as 0.00357 * FCH4. A project specific value for the percentage of methane in the gas is applied as this percentage would vary in different distribution grids. The factor 0.00357 is calculated from a factor of 5 m^3/m pipeline/year (at normal conditions) by multiplying with a density factor of 0.000714. The factor of 5 Nm3/m pipeline/year is the former official factor for cast iron at low pressure developed and utilized until 2005 by Gas Natural SDG to estimate the annual leakage of natural gas from their distribution network in Spain (PGM-087-E Rev. 2. Gas Natural SDG)[1]. This factor was defined using the PGM-087-E procedure, which was developed quite some years ago by experts at Gas Natural and was used to report to the Spanish government on the emissions from the grid. Gas Natural began to use a higher factor as of 2005 to establish its emissions for Spain. To update the emission factors used in Spain, Gas Natural contracted the Centro Politécnico Superior of the University of Zaragoza, Spain. Based on a study of emissions factors from various sources, they developed a factor of 7.8 Nm^3/m pipeline/year for cast iron pipes at low pressure (Barroso et al. 2005b). To be conservative, it was decided to use the lower old Gas Natural emission factor instead of the new emission factor as established by the University of Zaragoza.

PE

The UN base their data on tests in Spain. The emissions factor for leaks of natural gas in a low pressure distribution network (less than 50 mbar) with new polyethylene pipes (*EFNP)* is calculated in this methodology as *0.00021 * FCH4*. As for the cast iron pipes, a project specific value for the percentage of methane in the gas is applied as this percentage would vary in different distribution grids. The factor 0.00021 is calculated from a factor of 0.3 m^3/m pipeline/year (at normal conditions) by multiplying with a density factor of 0.000714. The emission factor of 0.3 Nm^3/m pipeline/year was defined in 2005 by the Centro Politécnico Superior of the University of Zaragoza, Spain (Barroso et al. 2005a). The EF is based on the results of field tests in Spain that measured the volume of gas lost to fugitive emissions in the existing polyethylene distribution network using the Pressure Variation Method.

[1] Note that this has since been reduced to 1.

Where:
EFOP = Methane emission factor of the old pipeline (t CH4/m*year)
EFNP = Methane emission factor of the new pipeline (t CH4/m*year)
FCH4 = Mass fraction of methane in natural gas

This means that the factor for LP PE pipe is 315 Nm3/km-year; a figure much higher than that assumed in the UK leakage model of 65.

In the Netherlands in 2004, an experimental study similar to that done in the UK in 2002 was undertaken. The study did analysed different types of infrastructure and found that a suitable emissions factor for PE LP mains was 210 m^3/km-year.

The US AGA has also done some *estimation* of the split of leakages by cause in the system in the US and has come up with this distribution[xxxvii]:

Table 2: Potential Methane Emission Estimates from the Natural Gas Distribution Stage and Reductions from the Natural STAR Program (2012)

	Gg	MMTe	Share
Pipeline leaks	631	13	49.5%
Meter/Regulator (City Gates)	503	11	39.4%
Customer Meters	103	2	8.0%
Routine Maintenance	4	0	0.3%
Upsets	35	1	2.8%
Potential Emissions Subtotal	1,276	27	100.0%
Voluntary Reductions	(45)	(1)	
Net Emissions	1,231	26	

Source: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012*, Annex 3, Table A-140

Figure 24. AGA estimates of shares of causes of leakage
With *estimated* leakage rates as follows:

Emissions Rates Calculations Based on EPA Inventory (2012)			Relevant Source
[A]	CH4 Natural Gas Systems (Bcf)	323	EPA
[B]	NG Fraction of Total Energy Content from Oil & Gas Production	27%	EIA
[C]	NG Fraction of CH4 from Petroleum Production (Bcf)	21	EIA, EPA
[D]	U.S. Gross Natural Gas Production (Bcf)	29,542	EIA
[E]	Methane Content of U.S. Pipeline NG	90.0%	AGA Estimate
([A]+[C])/([D]*[E])	Natural Gas Leakage - NG System as % of Total NG Production	1.27%	Calculation
[F]	Methane Emissions - Distribution Systems (Bcf)	64	EPA
[G]	U.S. Natural Gas Consumption (Bcf)	25,533	EIA
[H]	U.S. Natural Gas Volumes Delivered to Consumers (Bcf)	23,394	
[I]	LDC Natural Gas Volumes Delivered to Consumers (Bcf)	13,333	
[K]	Methane Content of Distribution System Natural Gas	90.0%	AGA Estimate
	Natural Gas Leakage - Distribution Systems as % of		
[F] / ([D] * [K])	Production	0.24%	Calculation
[F] / ([G] * [K])	Consumption	0.28%	
[F] / ([H] * [K])	Volumes Delivered to Consumers	0.31%	
[F] / ([I] * [K])	LDC Volumes Delivered to Consumers	0.54%	

The key figure for our study being 0.54%. Of course, these estimates are quite dependent on the network structure and materials of construction, so it is more valuable to focus on the individual factors in the assumptions as listed above.

The figures above contrast with the EPA calculations of 1997[xxxviii], which give the following data for GDN leakages:

- Distiribution M&PR stations: 773 x 10^6 m^3
- Leaks : 1178 x 10^6 m^3
- Blow and purge 62.3
- Total 2.18x10^9 m^3 (0.35% of gross national production)

The total is equal to 77 BCF per annum – the difference being estimated improvements in the network structure.

These estimation processes are based on simplistic models and are somewhat contested. Much of the contesting comes from researchers that have performed experimental measurements. However, Mitchell et al.[xxxix], reviewed the UK's (i.e. British Gas) procedures for estimating leakage and based their study on a critique of the methods used. This work was done in 1990, when the distribution system had less plastic, so the important findings are the relative differences between their estimates and the official ones. They used a more sophisticated analysis than the typical averaging based approach and used different scenarios for replacement/repair strategies. Their findings based on analysis of the network including all the different types of jointing (including mechanical and lead-yarn joints, MEG conditioning and so on) were as follows[xxxix]:

"British Gas maintains that the leakage rate is around 1% of supply.This paper estimates a Low, Medium and High Case leakage rate of 1.9%, 5.3% and 10.8% respectively. The authors are confident that the leakage rate is above 1.9% and consider it more likely that the leakage rate is between the Medium and High Case. This investigation has been very cautious in that only leakage from the low pressure, medium pressure and service pipelines has been calculated."

These discrepancies are most likely due to the fact that sample based factors may underestimate leakage rates unless sophisticated statistical analyses are used., in particular accounting for skewed distributions.

4.2 Estimated versus **measured** emissions

All of the leakage estimates described above and used to develop national figures are based on similar concepts of

i. Developing emissions factors from experiments and other data
ii. Making assumptions about network structures and materials of construction
iii. Applying the factors to obtain system-level values

There have been a number of studies in the literature which take a different approach to developing estimates by **measuring** actual emissions/methane concentrations either from the air or along roads, and then using models and statistical analyses to relate these to leakage rates. These take advantage of the particular chemical signatures associated with fossil methane.

The large majority of these studies (including one in London[xliii]) seem to indicate that the emissions (leakages) in city distribution systems are larger than those estimated through the three step process described above, and hence higher than the national inventories.

An overview study in Science[xl] looked at over 200 previous studies associated with experimental measurements in the USA strongly indicates that US emissions are considerably higher than official estimates, with natural gas infrastructure being an important element. The analysis, which is authored by researchers from seven universities, several national laboratories and federal government bodies, and other organizations, found these atmospheric studies covering very large areas consistently indicate total U.S. methane emissions of about 25 to 75 percent higher than the official EPA estimate. This is illustrated in the figure below, where a ratio of greater than 1 indicates that the measured emissions are higher than the estimate.

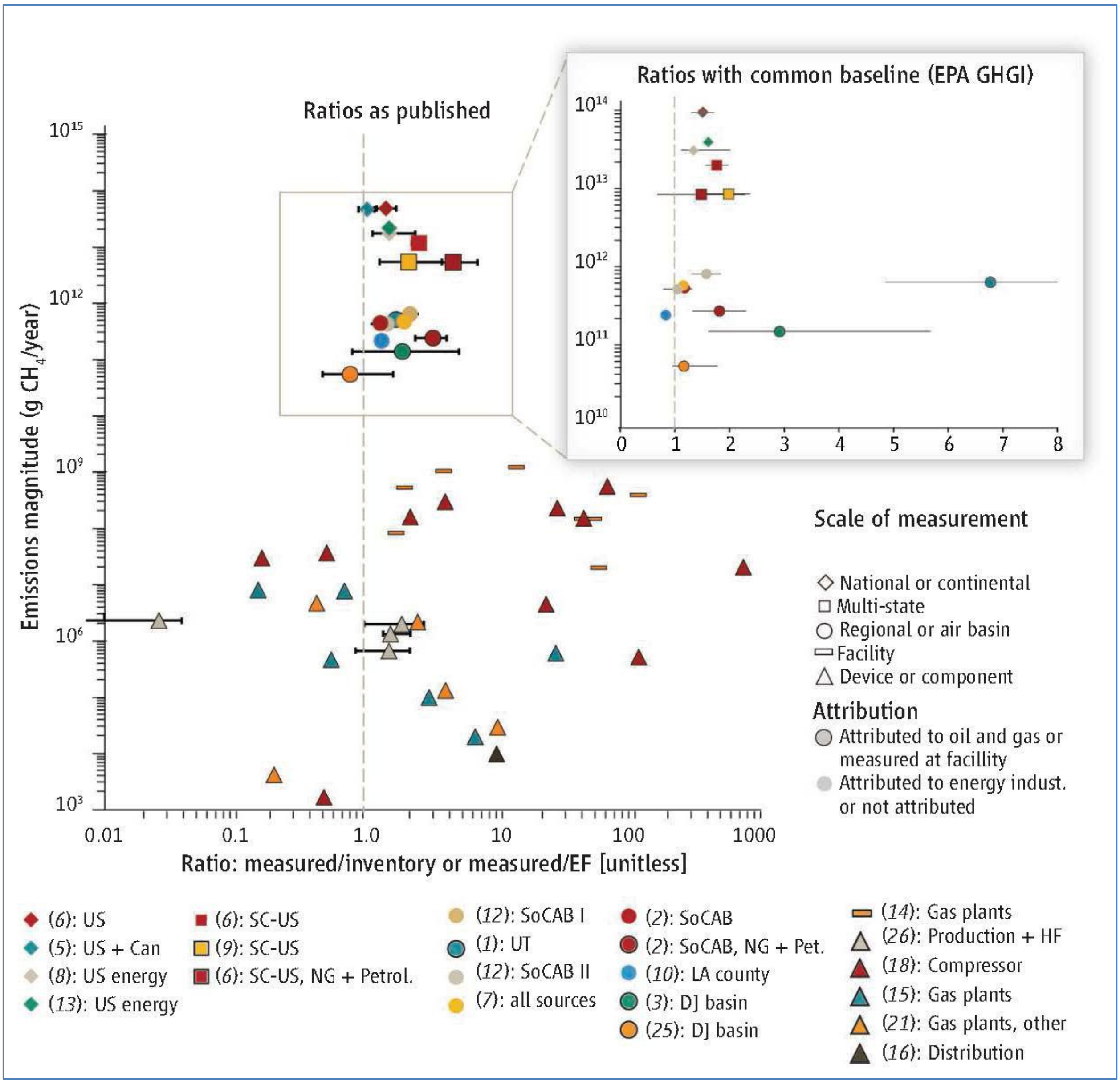


Figure 25. Ratios of measured and estimated emissions

The authors state:

> *"Across years, scales, and methods, atmospheric studies systematically find larger CH_4 emissions than predicted by inventories."*

They have several explanations for the discrepancies:

> *Why might emissions inventories be underpredicting what is observed in the atmosphere? Current inventory methods rely on key assumptions that are not generally satisfied. First, devices sampled are not likely to be representative of current technologies and practices. Production techniques are being applied at scale (e.g., hydraulic fracturing and horizontal drilling) that were not widely used during sampling in the early 1990s, which underlies EPA EFs.*

Second, measurements for generating EFs are expensive, which limits sample sizes and representativeness. Many EPA EFs have wide confidence intervals. And there are reasons to suspect sampling bias in EFs, as sampling has occurred at self-selected cooperating facilities.

Third, if emissions distributions have "heavy tails" (e.g., more high-emissions sources than would be expected in a normal distribution), small sample sizes are likely to underrepresent high-consequence emissions sources. Studies suggest that emissions are dominated by a small fraction of "superemitter" sources at well sites, gas-processing plants, coproduced liquids storage tanks, transmission compressor stations, and distribution systems. For example, one study measured ~75,000 components and found that 58% of emissions came from 0.06% of possible sources.

Last, activity and device counts used in inventories are contradictory, incomplete, and of unknown representativeness. Data should improve with increased reporting requirements enacted by EPA.

In the United States, the emission rates of particular gas industry components – from wells to burner tips – were established by the EPA in the 1990s. Since then, many studies have tested gas industry components to determine whether the EPA's emission rates are accurate, and a majority of these have found the EPA's rates too low. One of the important reasons for this is that average values are used; this assumes a broadly symmetric distribution of leaks. In fact, it appears that relatively few leaks in the gas system probably account for much of the problem. One earlier study examined about 75,000 components at processing plants. It found some 1,600 unintentional leaks, but just 50 faulty components were behind 60 percent of the leaked gas. Taking account of this type of distribution in practice would require a different leakage estimate model.

The authors calculate the underestimate of methane emissions in the USA national emission inventory as 14 Tg/yr (0.73 trillion cubic feet of methane, with a range of 7–21 Tg/yr). If all of this under-estimate is assumed to come from the natural gas system, the under-estimate alone represents roughly 2.6% of the volume in the 28 trillion cubic feet of natural gas produced in the United States.

A number of specific system studies are summarised below.

McKain et al.[xli] considered the natural gas infrastructure of Boston, USA, and found that the fractional loss rate in transmission, distribution and end use is 2.7%+/- 0.6%. They combine measurements, chemical analysis, modelling and consumption data to generate their findings. They note that their figure is much greater than the 0.7% estimate based on system parameters and leakage factors used at the national level as part of the national emissions inventory. This could indicate that estimation methods based on system characteristics can underestimate emissions. It is also higher than the figures used for the State of Massachusetts which has a higher iron based infrastructure and has an estimate of 1.1% leakage. McKain et al. also say that similar measurement-based studies in e.g. California give much higher emissions than estimate-based inventories.

McKain et al. also contrasted their figure of about 20 gCH4/m2-yr with that of other studies below. Note that this flux of methane relates to both leakage rates and network (population) density. Given that most figures are somewhat higher than 20, similar or higher leakage rates can be expected once consumption density is accounted for. Given that London has a similar density[2] and climate, it would be reasonable to assume similar or worse leakage rates.

Note that the weather in Boston is similar (if somewhat cooler than London), with average highs and lows in January of 2 and -6 C compared to 8 and 2C in London.

Table S1. Methane emissions in urban areas from atmosphere-based ("top-down") studies. Only studies that reported emission rates averaged in time and space are listed.

Ref.	Location	Measurement year	Emission Rate (g CH_4 m^{-2} yr^{-1})
43	Nagoya, Japan	1990-91	7
44	Midwest town, USA	1991	55
45	Two towns in East Germany	1992	12, 60
46	North Britain	1994	28 – 56
47	Heidelberg, Germany	1995-97	8 ± 2
48	Krakow, Poland	1996-97	20
49	St. Petersburg, Russia	1996-2000	32 ±9
50	Beijing, China	2000	50
51	Los Angeles County, CA, USA	2007-08	205 ± 6*
52	South Coast Air Basin, CA, USA	2007-08	228 ± 38*
53	Indianapolis, IN, USA	2008	71 ± 50
54	South Coast Air Basin, CA, USA	2010	167 ± 57*
55	South Coast Air Basin, CA, USA	2010	156 ± 14*
56	South Coast Air Basin, CA, USA	2010	127 ± 21*
57†	South Coast Air Basin, CA, USA	2010	160 ± 30*
57‡	South Coast Air Basin, CA, USA	2010	118 ± 30*
58	Florence, Italy	2011	58
59	London, UK	2012	66 ± 10

*Basin-total fluxes reported in the California studies were converted to average area fluxes using areas from the California Air Resources Board (42).
†Aircraft observations
‡Satellite observations

Figure 26. Measured methane emission rates for different urban areas

In line with this analysis, O'Shea et al.[xlii] (the London study in the table above) use airborne measurements and find that the emissions are 3.4 times larger than those associated with the national emissions inventory, again indicating that there is a potential for actual leakages to be higher than estimates, although this study did not distinguish between sources of CH4 (and the factor of 3.4 is against the total methane emissions from all sources in the inventory). This again provides strong evidence of actual leakage rates being higher than estimated ones. The fluxes were similar to those from studies in Indianapolis and Florence, while studies in Krakow give fluxes a factor of 2 larger in one case and in the case of only night-time observations, a factor of 4 smaller. This highlights the importance of averaging observations over time, which most studies perform. It is not clear over which time period the 2002 UK study data was averaged.

A different type of observation study was a road-based mapping of methane emissions[xliii] which mapped 785 miles in Boston in Aug-Oct 2011 and found 3356 leaks – an average of about 4.3 leaks

[2] Boston's population density is around 5000/km^2 and London's around 5500/km^2.

per mile. They found that the leak density correlated well with the proportion of cast iron in the local network:

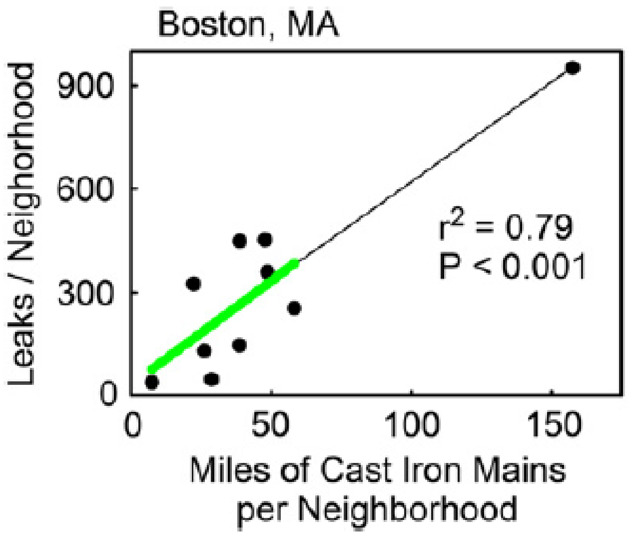


Figure 27. Leak prevalence versus cast iron proportion

A similar study for Washington DC[xliv] undertaken in Jan/Feb 2013 found 5893 pipeline leaks across 1500 road miles of the city; an average of around 3.93 leaks per mile. The researchers were also able to analyse four particular leaks in more detail. The estimated emission rates from the four leaks were 9200, 15 000, 30 200, and 38 200 l CH_4 per day.

Using an average of 20,000 l/day and 4 leaks per mile (=2.5 leaks per km) would give a leakage figure of around 18.25 Nm^3/m-yr; much larger than the figures of 0.5-5 in Figure 23 and related iron figures. Although it might be argued that these leaks are unusually large, this would point out the risk of using average figures drawn from a very skewed distribution where relatively few leaks might account for a large amount of leakage, and noting that the prevalence of such large leaks in the UK 2002 leakage study would be affected by the small sample size.

The same researchers also performed an analysis of “lost and unaccounted” (LAU) gas reported by commercial operators. The Pipeline and Hazardous Materials Safety Administration (PHMSA), monitors natural gas that is lost or unaccounted for during distribution. Lost and unaccounted (LAU) gas is defined as the difference between the amount of gas purchased (e.g., what enters the LDN) and the amount of gas sold (e.g., what is metered to consumers). Pipeline leaks and errors in metering both contribute to estimates of LAU gas. 174 companies with LDNs of at least 1000 pipeline miles were analysed. Across those companies, the average LAU gas term reported by each company in 2011 was 1.6%. The distribution across the companies is illustrated below.

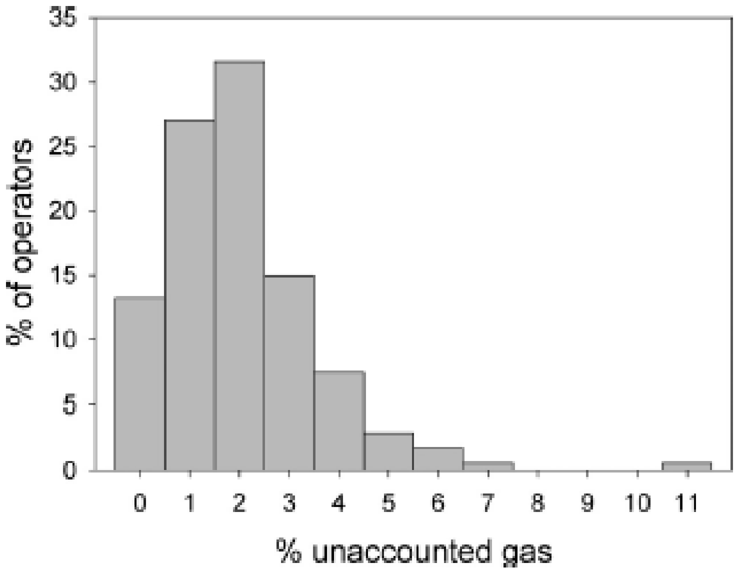


Figure 28. Distribution of % unaccounted gas across 174 operators

Fairley et al undertook a similar study over time for San Francisco. The resulting top-down (i.e. measurement based) estimates of CH4 emissions are found to decrease slightly from 1990 to 2012, with a mean value of 240 ± 60 $Gg_{CH4}.yr^{1}$ (at 95% confidence) in the most recent (2009-2012) period, and are 1.5-2.0 (at 95% confidence) times larger than the official Bay Area Air Quality Management District (BAAQMD) estimate of 125 Gg of methane in 2011. As the authors state:

> *"Currently, regional, state, and federal agencies, including the BAAQMD, estimate GHG emissions using bottom-up inventory methods that rely on a combination of activity data, emission factors, biogeochemical models and other information. Recent emission evaluations based on ambient measurements show that methane emissions for the US as a whole (e.g., Miller et al., 2013) and in California (e.g., Wennberg et al. 2012, Hsu et al. 2010; Singh et al. 2010; Jeong et al. 2013; Peischl et al. 2013) are underestimated by ~50% or more depending upon the area….*
> *…Relevant to urban areas, the US-EPA recently released a report identifying uncertainty in methane emissions from the natural gas distribution system as an area in need of further research (US-EPA, 2014)."*

This approach to leak monitoring has been scaled up by the Environmental Defense Fund and Google[xlv]; who demonstrate a new approach. They have chosen a large number of cities where they conduct drive-by leak surveys using vehicle-mounted devices, adding sophisticated mapping technologies. Examples of "methane maps" are shown below, where each circle indicates a leak and the darkness of the colour the extent of the leak. They found that the incidence of leaks varies between cities.

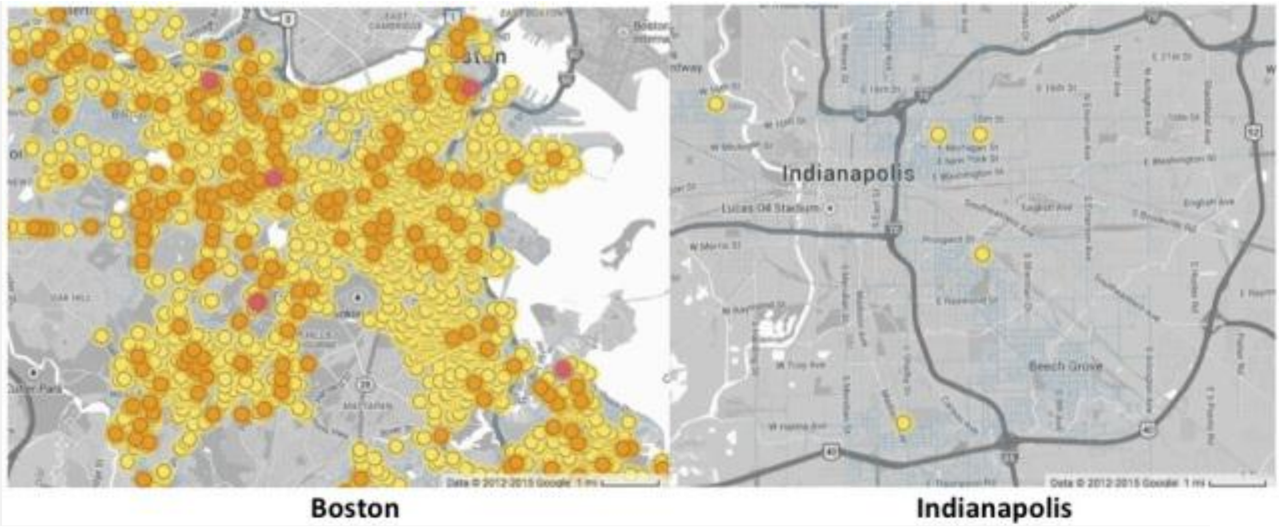


Figure 29. Comparison of gas leaks between Boston (old infrastructure) and Indianapolis (new infrastructure)

Barroso et al.[xxxvi] undertook comprehensive experimental programme to support the upgrading of the estimate factors in Spain for medium pressure (MP) polyethylene (PE) mains. They used 51 Spanish and 13 Mexican sites for the analysis and used the pressure variation method. They report:

> *"The results obtained confirm that the average emission factor for polyethylene gas distribution networks working at medium pressure is 0.46 +/- 0.15 Nm^3 $year^{-1}$ m^{-1}…. the experimental data reported here are thought to be representative of polyethylene medium pressure distribution lines in other countries, and might be useful to check existing leak calculation methods."*

They also note that in the EU, about 80% of the methane emitted to the atmosphere is attributed to natural gas released from the distribution systems and that these losses include: fugitive emissions (small and more or less continuous leaks from the flanges, valves and other elements of the network), pneumatic emissions in valves and gas vented due to maintenance works or incidents. In general, gas losses are not measured directly but are estimated according to the various methodologies available. Such estimates are known to involve large uncertainties and further work is needed to improve their reliability.

Their experimental results are described below.

Local emission factors from tests in Spanish networks, 2007.

Sites	p_g (bar)	L (m)	Emission factor (Nm^3/year/m)	Uncertainty (Nm^3/year/m)	Slope (Nm^3/year/m/bar)
Brion y Ames	2.50	15 300	1.47	0.09	0.587
Santullán	2.00	6100	1.43	0.05	0.717
Ayamonte	1.50	20 200	0.96	0.02	0.641
Mora	0.15	28 300	0.93	0.09	6.185
Grijota	2.50	16 000	0.88	0.03	0.351
Viladecavalls	2.00	17 300	0.83	0.58	0.416
San Antonio de Benajeber I	1.50	16 600	0.83	0.02	0.552
Galapagar IV	2.00	10 200	0.76	0.09	0.382
San Martín de la Vega II	0.15	43 900	0.65	0.31	4.310
Olias del Rey	0.15	10 800	0.60	0.44	3.994
Chinchón	0.15	14 400	0.48	0.12	3.216
Azucaica	2.00	14 000	0.42	0.01	0.212
Mediana	0.15	18 200	0.41	0.08	2.706
Valdeolmos Alalpardo I	0.15	5300	0.39	0.11	2.604
Arteixo	2.00	42 400	0.39	0.01	0.195
Brunete	2.00	19 800	0.37	0.01	0.184
Valdeolmos Alalpardo II	0.15	1400	0.14	0.06	0.932
Colmenar de Oreja	0.15	19 200	0.13	0.01	0.856
Vilalba	2.50	19 000	0.10	0.08	0.039
Granja García	2.50	7010	0.09	0.05	0.035
Cabezón de Pisuerga	2.00	7000	0.08	0.05	0.042
Beranga	2.00	6200	0.08	0.05	0.039
Valdeolmos Alalpardo III	0.15	5000	0.05	0.03	0.318
Turis	0.14	3600	0.04	0.02	0.317
Cangas	2.50	24 070	0.04	0.03	0.017
Villatuerta	0.10	3300	0.04	0.07	0.414
Puerto Sagunto	3.00	63 100	0.01	0.02	0.003
Albalat de Rivera	0.15	41 700	0.00	0.00	0.018
Penilla Sarón	2.00	11 900	0.00	0.58	0.000

Figure 30. Emission (leak) factors from Spanish gas networks (experimental results)

They note that the largest contribution to the global uncertainty comes from the extrapolation of results from the sample sites to the whole network, while the errors in the estimation of local emission factors display a lower influence.

As a result of their analyses, a new procedure for estimation of gas leakage was proposed to and approved by the Environment Ministry, changing the emission factors from 1 to 0.46 Nm3/year/m for MPB polyethylene and from 5 to 1 Nm3/year/m for APA steel. This shows the potential value of an experimental programme.

Taking the lower pressure mains of the Spanish experiments and extrapolating to 30 mbarg using the slope in the last column above, we obtain the following results:

town	pressure	emissions E spain	U	slope (E/bar)	UK pressure	E spain @ 0.03 bar	
Villatuerta	0.1	0.04	0.07	0.414	0.03	0.01102	
Turis	0.14	0.04	0.02	0.317	0.03	0.00513	
Mora	0.15	0.93	0.09	6.185	0.03	0.1878	
San	0.15	0.65	0.31	4.31	0.03	0.1328	
Olias	0.15	0.6	0.44	3.994	0.03	0.12072	
Chincho´n	0.15	0.48	0.12	3.216	0.03	0.09408	
Mediana	0.15	0.41	0.08	2.706	0.03	0.08528	
Valdeolmos	0.15	0.39	0.11	2.604	0.03	0.07752	
Valdeolmos	0.15	0.14	0.06	0.932	0.03	0.02816	
Colmenar	0.15	0.13	0.01	0.856	0.03	0.02728	
AVERAGE						**0.076979**	Nm3/m-yr

Which is around 18% higher than the UK value, but more importantly, the table indicates the wide ranges that arise from such studies; the range is between 11 and 180 Nm3/km-year (compared to 63.51 for the UK); this demonstrates the variance between experiments and the risks around sample size, and we are extrapolating from medium to low pressures.

Netherlands study[xlvi]

In 2004-5, a number of experimental measurements (similar to the UK 2002 study) were undertaken in the Netherlands gas distribution sytem with a view to updating leakage model factors, combining leak frequence data with typical leakage rates for differnet pressure ranges and materials. A limited number (25) of locations were used for estimating individual leakage rates. . Taken together, these are used to generate leakage rate estimates for the Dutch GDNs.

The materials and pressures studied were:

- low pressure (30 – 100 mbar)
- medium pressure (1 - 4 bar)
- high pressure (8 bar) gas distribution grids:
- polyethylene (PE)
- polyvinylchloride (PVC) (unmodified and high impact)
- steel, grey cast iron
- ductile cast iron
- asbestos cement.

The lengths of the gas distribution network in the Netherlands are given for each material and pressure range in 2004 are given below. Note that less than 0.4% of the material is unidentified, indicating good quality network composition data. The UK distribution is not published in this way.

Material	Pressure Range [bar]	Length in 2004 [km]	Percentage of total [%]
Polyethylene	0.03 – 0.1	9,560	7.8
PVC - Unmodified	0.03 – 0.1	22,636	18.6
PVC - High Impact	0.03 – 0.1	48,648	39.9
Steel	0.03 – 0.1	5,592	4.6
Grey Cast Iron	0.03 – 0.1	7,184	5.9
Ductile Cast Iron	0.03 – 0.1	1,502	1.2
Asbestos Cement	0.03 – 0.1	1,828	1.5
Unknown	0.03 – 0.1	280	0.2
Polyethylene	1.0 – 4.0	7,219	5.9
Steel	1.0 – 4.0	975	0.8
Grey Cast Iron	1.0 – 4.0	184	0.2
Ductile Cast Iron	1.0 – 4.0	331	0.3
Unknown	1.0 – 4.0	16	0.0
Polyethylene	8.0	2,049	1.7
Steel	8.0	13,037	10.7
Ductile Cast Iron	8.0	630	0.5
Unknown	8.0	17	0.0
Unknown	Unknown	283	0.2
Total		**121,971**	**100.0**

Figure 31. Composition/length of Netherlands gas distribution network (2004)

The GDNs survey the whole network for leaks every five years, using above ground instruments at first and then below ground when leaks are found and repaired. The recording of these leaks gives rise to leak frequency statistics by pressure and material, which are again collected, organised and analysed (see Figure 32). It is not clear whether an equivalent analysis is undertaken in the UK, but it would be recommended since it is part of the standard leak detection and response protocol in the Netherlands.

Material	Pressure Range [bar]	Number of leakages per length of mains supply per year [#/km year]
Polyethylene	0.03 – 0.1	0.06
PVC - Unmodified	0.03 – 0.1	0.04
PVC - High Impact	0.03 – 0.1	0.02
Steel	0.03 – 0.1	0.13
Grey Cast Iron	0.03 – 0.1	0.29
Ductile Cast Iron	0.03 – 0.1	0.11
Asbestos Cement	0.03 – 0.1	0.09
Unknown	0.03 – 0.1	0.13*
Polyethylene	1.0 – 4.0	0.02
Steel	1.0 – 4.0	0.02
Grey Cast Iron	1.0 – 4.0	0.16
Ductile Cast Iron	1.0 – 4.0	0.13
Unknown	1.0 – 4.0	0.63*
Polyethylene	8.0	0.17
Steel	8.0	0.02
Ductile Cast Iron	8.0	0
Unknown	8.0	1.80*
Unknown	Unknown	0*

Figure 32. Number of leakages per length for GDN mains in the Netherlands (2004)

Together with leakage rate experiments, this gives rise to the overall results for emissions factors:

Material	Pressure Range [bar]	Length in 2004 [km]	Number of leakages per length per year [#/km year]	Leakage rate [litre/hour]	Emission factor [m^3 CH_4/km year]	Emission [10^6 m^3 CH_4/ year]
Polyethylene (PE)	0.03 – 0.1	9,560	0.06	180	210	2.0
PVC - Unmodified	0.03 – 0.1	22,636	0.04	180	140	3.1
PVC - High Impact	0.03 – 0.1	48,648	0.02	180	70	3.6
Steel	0.03 – 0.1	5,592	0.13	20	50	0.3
Grey Cast Iron	0.03 – 0.1	7,184	0.29	110	620	4.4
Ductile Cast Iron	0.03 – 0.1	1,502	0.11	160	340	0.5
Asbestos Cement (AC)	0.03 – 0.1	1,828	0.09	180	320	0.6
Unknown	0.03 – 0.1	280	0.13	180	440	0.1
Polyethylene (PE)	1.0 – 4.0	7,219	0.02	270	90	0.6
Steel	1.0 – 4.0	975	0.02	170	80	0.1
Grey Cast Iron	1.0 – 4.0	184	0.16	170	540	0.1
Ductile Cast Iron	1.0 – 4.0	331	0.13	170	420	0.1
Unknown	1.0 – 4.0	16	0.63	170	2,050	0
Polyethylene (PE)	8.0	2,049	0.17	270	880	1.8
Steel	8.0	13,037	0.02	170	60	0.8
Ductile Cast Iron	8.0	630	0	170	10	0
Unknown	8.0	17	1.80	170	5,900	0.1
Unknown	Unknown	283	0	170	0	0
Total		**121,971**				**18.3**

Figure 33. Emissions factors by material and pressure in the Netherlands GDNs (2004)

These are also aggregated into two distinct emission factors used in the Dutch emissions inventory calculations:

- 610 m^3 or 437 Gg methane/km per year for grey cast iron

- 120 m^3 or 86 Gg methane/km per year for other materials

It is important to note that the PE estimate is around three times that of the UK and would lead to an increase in the UK's leakage estimate of 80% if this figure replaced the PE mains LP estimate in the UK.

Although a large number of studies, especially those using atmospheric monitoring of methane concentrations, indicate that leakages are larger than official estimates, one study which is based on sampling of leaks in a set of representative networks in the USA[xlvii] and extrapolating the leakage rates nationwide concludes that national estimates may somewhat overestimate the actual leakage rates by around 1.4 to almost 3. However, the authors acknowledge that their estimates may be biased by the choice of networks to sample from (only companies that volunteered to take part in the study were analysed).

The distribution of leaks was as below.

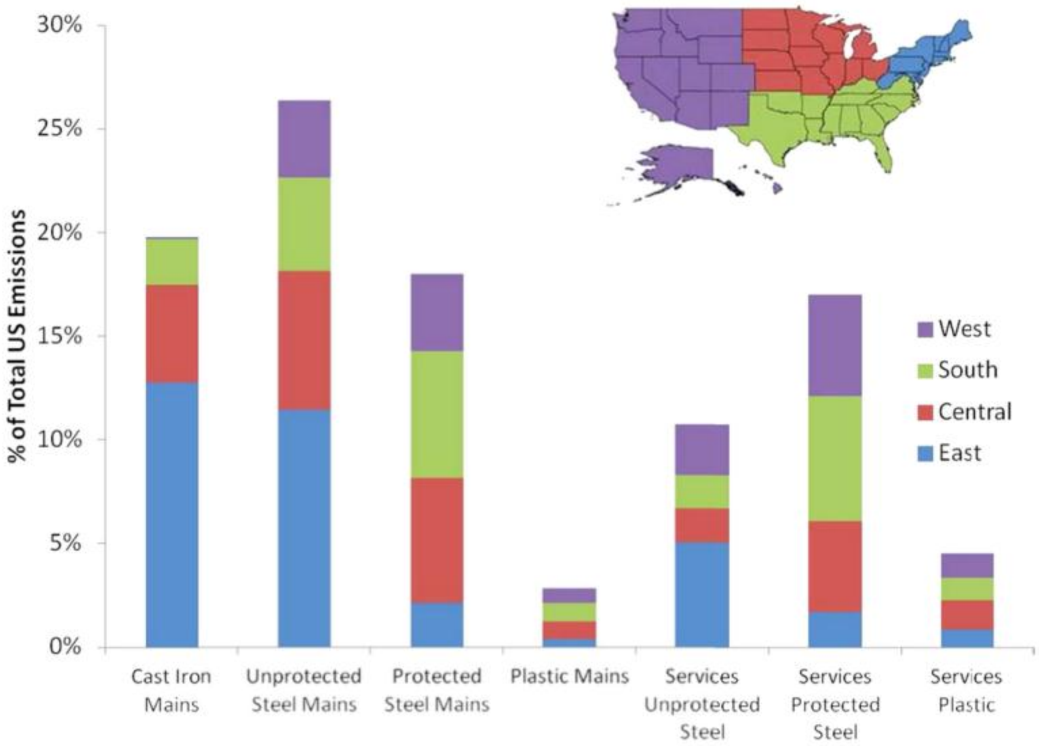
category	this study: methane emissions (Gg)	this study: 95% upper confidence limit (Gg)	EPA 2011: methane emissions (Gg)
		pipelines	
mains	132	431	429
services	63.6	124	194
pipeline subtotal	197	554	623
		equipment	
M&R facilities	42.3	82.9	552
customer meters[a]	112	150	112
maintenance	1.6	2.5	3.7
upsets	41.6	64.1	38.9
equipment subtotal	197	300	706
total	393	854	1329

[a]EPA emission factor used for this category.

Figure 34. Comparison of leak sampling approach and EPA inventory

In this study, the leakage rates (of order 10 g / min per leak) were comparable to the 20,000 l per day reported above[xliv], so it is assumed that the number of leaks per mile were less in the sampled case than the whole city cases for the Boston and Washington DC cases.

The distribution of causes above can be compared with the *estimated* distribution from the



American Gas Association in[xlviii]

Figure 35. Percentage of total US methane emissions from underground pipeline leaks by region and pipeline type and category.

The sample extrapolation approach resulted in the following distribution across types of infrastructure and geographies:

A Russian study[xlix] also results in a distribution of amounts and causes of leaks as below; these indicate the significance of distribution losses and importance of sealing.

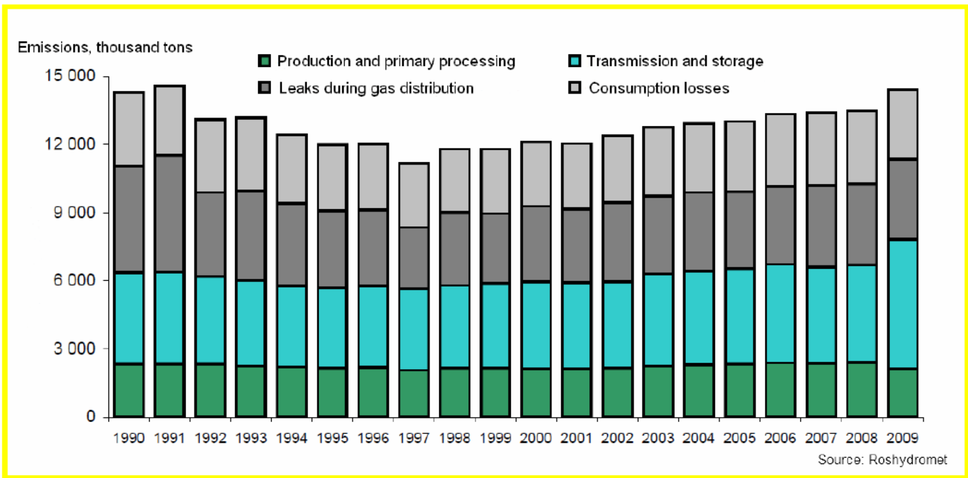


Figure 36. Leakage amounts from different parts of the Russian natural gas infrastructure

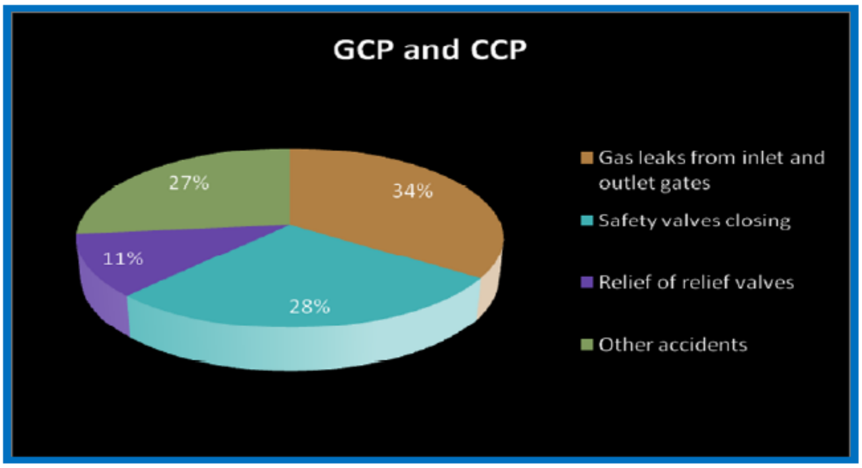


Figure 37. Causes of leaks at gas control points (GCP) and cabinet-type gas control points (CCP) in Russia

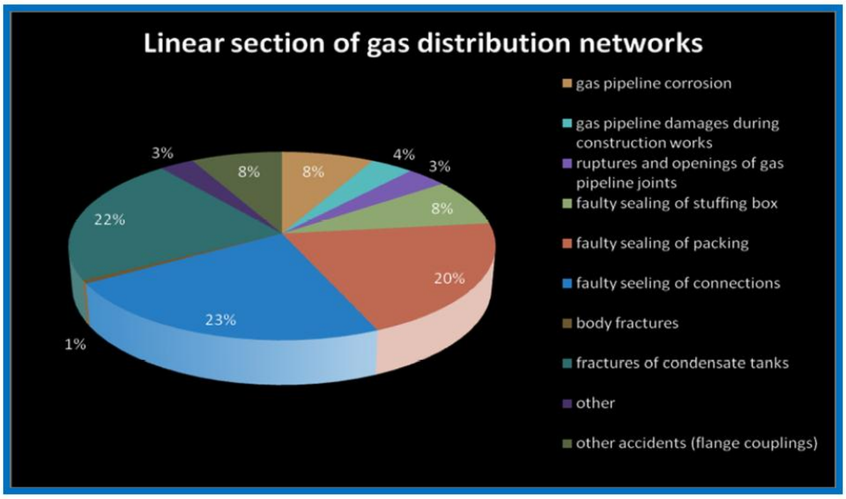


Figure 38. Causes of leaks in linear sections of gas distribution networks in Russia

An analysis of Titas Gas in Bangladesh[l] found leakage rates of around 2.1% in above ground installations (AGIs).

A key feature of leakage estimates is the large amount of uncertainty involved. Allen[li] (2014) undertook a review of estimate methodologies and concluded:

> *"Estimates (of leaks) that have appeared in the scientific literature in the past several years have ranged from slightly over 1% (volume of methane emitted as a percentage of the volume of natural gas produced) to more than 10%".*

The reasons for the uncertainty are firstly, the large population of sources; secondly, the difference between approaches based on ambient methane concentration measurements (top-down methods) and approaches based on direct measurement of emissions from individual sources (bottom-up methods) and finally, the difference in the extreme values of emission rates, compared to mean emission rates from many of the emission sources in the natural gas supply chain (a 'fat-tail' distribution, where relatively few sources are responsible for a large share of leaks and which may not potentially show up in a small sample of the network).

Allen states that the difficulty with ‘bottom- up’ approaches where parts of the infrastructure are sampled (the current approach in the UK) is obtaining a truly representative sample from a large, diverse population. If emissions were normally distributed about a mean value, obtaining a representative sample would be reasonably straight forward. For many types of emission sources in the natural gas supply chain, however, extreme values can strongly influence average emissions.

Miller et al.[lii], and Brandt et al.[xl] also summarised recent estimates and both conclude that ambient measurements suggest understimates of methane emissions in bottom-up inventories.

4.3 Regulation and policy

There are a number of studies which review current policy regarding leakage and in some cases make recommendations for improvements.

The WRI[liii] reviewed the situation in the US. The current situation is as follows:

- Most states require the classification of distribution leaks into one of three tiers: those that pose an imminent danger and require immediate attention (Tier 1), those that pose some risk and should be fixed within a reasonable amount of time (Tier 2), and those that do not pose much risk but should be monitored on a regular basis (Tier 3).
- Note that under this system, large leaks that do not pose a risk to people or property do not require immediate attention, even though they may be emitting significant quantities of methane.
- Some regulators (e.g. in California) have created a fourth tier (in between Tier 1 and Tier 2) which requires that these types of leaks should be fixed "as soon as is practicable". In California, the state's Public Utilities Commission (the key regulator, similar to OFGEM) is charged with finding ways to require natural gas distribution utilities to locate and repair leaks, in particular to target large leaks that do not necessarily pose a health or safety risk, but would require "the maximum technologically feasible and cost-effective avoidance, reduction, and repair of leaks and leaking components…within a reasonable time after discovery."
- Similarly, Connecticut, New York, and Pennsylvania—three of the states with the most miles of cast iron pipelines—have set goals for complete replacement with plastic or coated steel by 2080, 2090, and 2111, respectively[liv].

Jackson et al.[xliv], who undertook the leak measurement study in Washington DC, also made some policy recommendations. They suggest that there is a need for financial incentives to fix leaks which in turn will save money, particularly incentives to replace cast-iron, bare steel, and other older, unprotected mains. Recently, the U.S. Energy Information Administration determined that $3.1B worth of natural gas was lost and unaccounted for annually in the United States between 2005 and 2010. A more recent report estimated that U.S. consumers paid more than $20 billion between 2000 and 2011 for lost and unaccounted for natural gas.

They identified several barriers to pipeline repair and replacement, as cost recovery for pipeline repairs by distribution companies is often capped by Public Utility Commissions (PUCs). Furthermore, consumers often pay for all or most of the lost-and unaccounted- for gas through user fees, meaning that the local distribution company has less financial incentive to fix leaks than might be predicted from the value of lost gas alone.

To overcome the barriers to fixing pipeline leaks, PUCs could allow distribution companies to recover funds to accelerate pipeline replacement faster than a typical 40-year replacement cycle. For instance, New Hampshire implemented a Cast Iron/Bare Steel (CIBS) replacement program that allows the distribution companies to recover repair costs.

Other mechanisms that have been suggested include the application of carbon−offset programs and placing a price on carbon emissions (e.g., a carbon fee or a cap-and-trade system) – similar to the Environmental Emissions Incentive in the UK.

The Environmental Change Institute, in its Methane UK report[lv] state that mitigation of methane emissions from the pipeline network can be achieved simply by replacing old cast iron pipes with modern plastic piping but note that this is a laborious and costly process, involving labour-intensive construction work and that although there are some in improvements in operating efficiency to be made by minimising leaks, the relatively low cost of gas, especially compared to the cost of upgrades, means there is little economic incentive to do so.

ECI go on to state that the industry would benefit from a focus on cost effective technologies and practices that improve operational efficiency and reduce emissions of methane. For example, the USA's Natural Gas STAR Programme[lvi] encourages the natural gas industry to reduce emissions through market based activities that are both profitable for industry partners and beneficial to the environment.

The implementation of the programme has resulted in some best management practices to achieve emissions reductions at all stages of the gas system. It worked as follows: opportunities and options to reduce leaks and venting from the largest sources were jointly identified by EPA and gas industry representatives and it is intended to reproduce these solutions across all sectors.

ECI note that carbon trading (and therefore other credit based systems) could support emissions reductions but that (in the UK):

> *"the lack of reliable data means there is a risk of introducing 'hot air' into the trading scheme where the gas industry could be rewarded for apparent reductions due to statistical error rather than 'real' savings."*

ECI also state:

> *"However, it is debatable as to whether the industry should be rewarded for carrying out repairs that should be done as a matter of course. It is Ofgem's responsibility to ensure the necessary investment in pipeline infrastructure is made and maintained in the long term. Direct legislation through, for example, mandatory standards for leakage, is required to secure further emissions reductions. Improved data would also help in monitoring and enforcing such targets."*

The US EPA also comments in detail on the alignment of incentives[lvii]. They have not directly issued regulations to control methane emissions from distribution pipelines, partnered with PHMSA to control such leaks, nor developed a strategy to address barriers that inhibit the mitigation of methane leaks in the natural gas distribution sector.

The EPA note that while the Natural Gas STAR program has been successful in reducing methane from other segments of the industry, this voluntary program has achieved limited reductions from leaking distribution pipelines, due largely to financial and policy barriers. An example of the latter is the need for GDNs to bear the upfront capital costs for repairs, while benefits accrue to the consumer, creating a disincentive to repair non-hazardous leaks. They note that in addition to the GHG issue, the methane leaks from distribution pipelines in the US represented losses of $192m p.a. In 2012, the Natural Gas STAR program achieved a total of 66 billion cubic feet in methane emissions reductions from the natural gas industry. Reductions from the distribution sector accounted for only

1 percent of this. In comparison, reductions from the production sector accounted for 82 percent, and reductions from the transmission sector accounted for 15 percent.

The limited emission reductions achieved by the distribution sector are due in large part to the fact that GDNs have little financial incentive to reduce methane emissions from leaking pipelines that do not pose a potential safety hazard. GDNs typically do not own the gas that flows through their pipeline networks. In the US, GDNs are generally allowed to pass on to their customers the costs of gas that is "lost and unaccounted for" from the pipeline system, including gas lost to leaks. The benefits of repairing leaks (i.e., gas savings) are passed on to the consumer. *Thus, in the US system there is a financial disincentive for GDNs to proactively locate and repair leaks.* The cost of the product lost (i.e., natural gas) is easy for GDNs to recover while the costs to repair, replace or retrofit pipelines poses more of a cost recovery challenge.

State public utility commissions (PUCs) regulate the rates and services of GDNs. These are similar to OFGEM in terms of their operation. Their policies can create barriers to reducing methane emissions from leaking pipelines. Repairing or replacing pipeline involves significant capital investments, and the GDN generally has to carry these costs until they can be recovered. In the US, cost recovery is usually not permissible until after the filing of a rate case, a proceeding through which a GDN applies to the PUC for a rate increase. A rate case can create a "regulatory lag" in that the GDN is responsible for bearing the costs of pipeline replacement and repair until the rate increase takes effect and the GDN begins to recover its costs. This is not the case in the UK.

Another barrier to replacing and repairing pipelines in the US involves the traditional practice of charging customers for the amount of gas used based on a per-unit price. This practice promotes pipeline expansion rather than repair and replacement because expansion will increase the GDNs customer base, resulting in more gas sold and revenue earned. Conversely, investing in improvements to existing infrastructure will lead to increased gas rates, which will deter consumption and potentially result in lost revenue for the GDN. Elements of this situation can be argued to exist in the UK.

In recognition of these financial and policy barriers, some PUCs have taken steps to improve cost recovery mechanisms for their GDNs.

PUCs have to balance goals— such as ensuring consumers receive safe and reliable service at reasonable rates— while allowing GDNs an opportunity to earn a fair rate of return. There are a number of financing mechanisms that allow GDNs to recover capital expenditures for fixing leak-prone pipelines on an annual basis. These mechanisms can decrease GDNs' capital recovery times and diminish the disincentives to repair and replace leaking pipelines.

Natural Gas STAR representatives told the EPA PUCs could play a key role in reducing methane emissions from the distribution sector. They said the Natural Gas STAR program could work with PUCs in developing a new financial model, which alters the current incentive structure of GDNs to proactively repair more leaks should help the EPA's voluntary programs achieve results.

The Federal Energy Regulatory Commission (FERC), which sets rates for the country's interstate natural gas pipelines, launched a new docket recently. FERC proposes to allow pipelines to recover capital expenditures made to enhance reliability, improve safety and meet environmental objectives. This would be allowed outside of the normal rate-setting process. The proposal is reproduced below.

FERC Proposes Policy on Cost Recovery for Natural Gas Facilities Modernization

The Federal Energy Regulatory Commission is seeking public comment on a proposed policy statement that would allow interstate natural gas pipelines to recover, through surcharge or tracker mechanisms, certain capital expenditures made to modernize pipeline system infrastructure to enhance reliability, safety and regulatory compliance.

As a result of regulatory reforms by the Pipeline and Hazardous Materials Safety Administration, interstate pipelines likely will face new standards requiring significant capital cost expenditures to enhance the safety and reliability of their systems. Under recent Environmental Protection Agency initiatives, they also may face increased environmental monitoring and compliance costs, as well as a need to replace or repair existing compressors and other facilities.

The proposed policy statement is meant to ensure that existing Commission ratemaking policies do not create barriers to the ability of pipelines to expedite needed or required upgrades and improvements. In addition to allowing recovery of modernization costs, FERC may consider capital costs to replace compressor facilities or make other improvements in response to increased federal or state environmental regulations as eligible for inclusion in the surcharge.

Under the proposed policy statement, which is based on principles in a January 2013 FERC order that allowed Columbia Gas Transmission LLC to implement such a tracker, a pipeline seeking a cost-recovery surcharge would have to meet five standards:

- *The pipeline's base rates must have been recently reviewed through a Natural Gas Act general section 4 rate proceeding or through a collaborative effort between the pipeline and its customers.*
- *Eligible costs must be limited to one-time capital costs incurred to meet safety or environmental regulations, and the pipeline must specifically identify each capital investment to be recovered by the surcharge.*
- *Captive customers must be protected from cost shifts if the pipeline loses shippers or increases discounts to retain business.*
- *There must be a periodic review to ensure rates remain just and reasonable.*
- *The pipeline must work collaboratively with shippers to seek their support for any surcharge proposal.*

Comments on the proposed policy statement are due 30 days from the date of publication in the Federal Register, with reply comments due 20 days later.

The Bipartisan Policy Center's report also makes some policy recommendations for pipeline replacement:

Policy Mechanisms for Pipeline Replacement

A robust natural gas pipeline system is important for a variety of safety, reliability, and environmental reasons. As discussed above, one of the greatest environmental motivators is the drive to capture the full climate benefits of increased natural gas production and use, which is served in part by reducing methane emissions from natural gas transportation infrastructure. Although pipeline replacement may not be economically justified for emissions reductions alone—at least at the current time—these reductions are surely a cobenefit of replacements conducted due to safety and reliability concerns.

There are several approaches to incentivizing the replacement of critical, at-risk natural gas pipelines for the achievement of these goals. These include cost recovery through rate cases, as well as alternative approaches, such as infrastructure cost trackers and base rate surcharges. In general, solutions to replacement challenges will vary based on the individual operators, systems, and utility commissions involved.

Governmental and other organizations have reiterated the need for pipeline investment. In 2011, the U.S. Department of Transportation and PHMSA developed a Pipeline Safety Action Plan to "accelerate rehabilitation, repair, and replacement programs for high-risk pipeline infrastructure." Similarly, NARUC issued a resolution on July 24, 2013, that:

- *Calls on regulators and industry to consider programs to quickly replace the most*
- *vulnerable pipelines while adopting rate recovery mechanisms to address utilities'*
- *financial realities;*
- *Directs state commissions to explore alternative rate recovery mechanisms for*
- *pipeline modernization, replacement, and expansion; and*
- *Encourages members' dialogue with all relevant stakeholders, including the public.*

Natural gas operators may also be able to pursue GHG emissions reduction strategies other than pipeline replacement, such as the cost-effective technologies and practices recommended by EPA's Natural Gas Star Program. These cover a broad spectrum, including technologies related to compressors/engines, dehydrators, pneumatics/controls, tanks, and valves, as well as suggested practices for inspection, testing, maintenance, and repair. The capital costs for these projects range widely (up to $50,000 or more), though many are described as requiring $1,000 to $10,000 or less.

A report authored by EPA's inspector general points out that although the program has been successful in reducing methane emissions from some parts of the industry, it has had limited success in the distribution sector due primarily to financial and policy barriers.

4.4 Summary of Key Findings

This section of the report has focussed on data from other countries, data from empirical studies (i.e. measured data) and policy recommendations made elsewhere.

The key findings are:

1. Other countries use a similar approach to the UK in that a combination of activities (e.g. network structure) and emissions/leakage rates are used to estimate leakage.
2. These countries also acknowledge the significant uncertainties associated with this approach, which is based on small sample sizes of particular networks.
3. Two key assumed figures - PE service leakage rates and PE mains leakage rates – are higher in other countries than in the UK.
4. There is increasing focus on these emissions/leakage rates as countries become more concerned about accurate reporting of greenhouse gas (GHG) emissions, noting that methane emissions constitute a significant of national inventories.
5. Empirical studies based on measured emissions tend to indicate that the actual emissions are larger than the estimated ones; the overall review in Science[xl] indicates a factor of 25-75% for the USA. A study for London[xlii] indicated a factor of over three times (accounting for all emissions sources).
6. New, non-invasive technology is making the mapping and estimating of leakage much cheaper and more straightforward, e.g. the Environmental Defense/Google Study[xlv]. This could be an activity which is complementary to a new experimental leakage study.
7. The US regulators express concern that the current policy measures are not driving innovation or reduction in leakage rates as expected.

5 Leakage in other industries

5.1 UK Water Industry

5.1.1 Overview

Leakages in the water network have a number of causes[lviii].

Although the industry is transitioning towards plastic pipes, large proportion of the UK's water mains are made or iron or lead, including Victorian era infrastructure. There are also a high number of joints, fittings, interconnections and relatively short pipe which provide multiple opportunities for leaks to occur. Combined with higher supply pressures than originally envisaged, leakage is inevitable. In more detail, leakage arises from four main causes:

- Higher supply pressures which exceed the original parameters of installed pipework (particularly older pipework) and can cause pipes and/or joints to rupture or burst
- Corrosion of metallic infrastructure: rusting of pipes, fittings and joints steadily reduces their integrity, eventually resulting in failure. Corrosion can arise from both within the pipe, such as acidic waters from upland areas, and outside of the pipe where the external pipe wall is attacked by elements in the soil. In both cases, the resulting corrosion can weaken the pipe wall, reducing its ability to withstand the current supply pressure.
- Erosion, which usually occurs where a leak has already formed as jets of water from the leak collect sand or stones from the environment which then hit the pipe, gradually weakening it and increasing the likelihood of a secondary leak
- Soil characteristics, where changes at the point of installation can have a material impact on the pipeline. Changes in temperature and moisture can cause the soil to expand and contract, potentially causing the pipeline to bend. Movements in the soil can also cause movement of the pipeline and its associated fittings, increasing the risk of damage and failure.

Overall, the rate of leakage is of the order of 20% in England and Wales and somewhat higher in Scotland.

OFWAT is the key regulator in the water industry for England and Wales and sets the overall strategy and policy around leakage. A good summary of leakage is in the National Audit Office document "Leakage and Water Efficiency"[lix].

The regulator has two main functions in relation to leakage which are:

- To set targets for leakage reduction, through a mix of mandatory targets for some companies and close monitoring for others.
- To establish a framework for the "economic level of leakage" i.e. that level of leakage at which further investment would not be warranted from a cost-benefit analysis and would lead to a rise in the price of water for consumers. This is based on comparing the long run marginal cost (LRMC) of supplying 1m^3 of water versus the cost of avoided leakage of the same quantity.

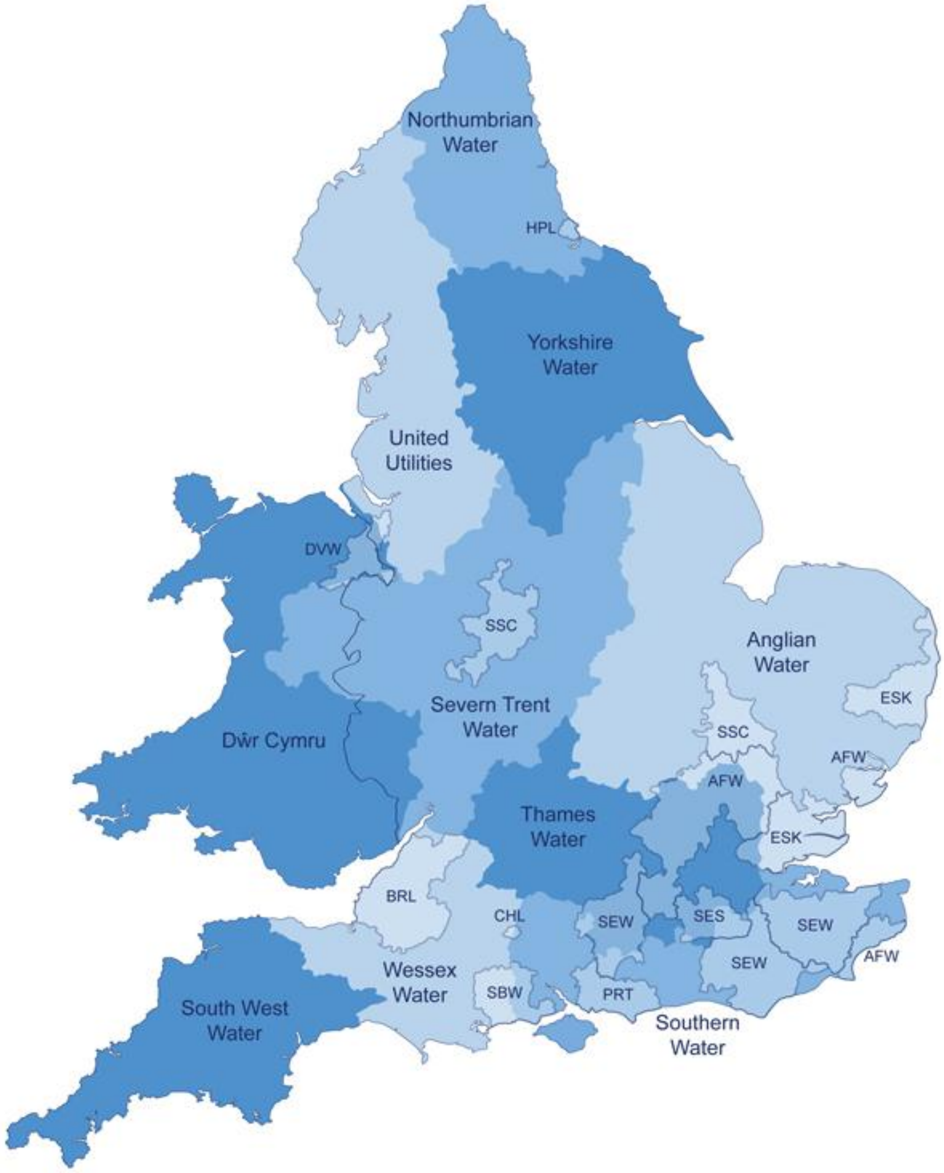
OFWAT are supported by the Environment Agency in these analyses.

In England and Wales, the overall water system is different from gas since it is the same commercial entity that operates the infrastructure system and acts as the supplier to the end-user (see Figure

39), so there are (in principle) incentives in place to reduce losses. This is because the system operator's costs reflect the amount of water treated and supplied into the network, and the revenues reflect consumption (metered and estimated).

In the late 1990s the regulator recognised that these nevertheless were not strong enough to drive behaviour hence the introduction of mandatory leakage reduction targets. These were then estimated to have resulted in system benefits of £13-39 million per year in operating costs across all companies. This is because leakage levels had not been reduced to the "economic level of leakage", ELL, as the prevailing incentive to do so was not strong enough.

The situation is of course difference with gas, where the GDN and end-user suppliers (gas suppliers) are different companies, and hence although there may well be an economic benefit overall to reducing leakage, it is not as easy to attribute this benefit to a single entity. Note that there is no NTS



or inter-network linkage for water (although the idea is mooted from time to time).

Figure 39. England and Wales water companies

Ofwat sets each company an annual leakage target. These targets are based on each company's assessment of its ELL challenged by Ofwat and the EA. The industry's targets for the past 11 yearsand future five years appear below.

Year	2004-05	2005-06	2006-07	2007-08	2008-09	2009-10	2010-11	2011-12	2012-13	2013-14	2014-115
Target (Ml/d)	3,598	3,551	3,485	3,410	3,330	3,295	3,294	3,278	3,266	3,250	3,243

Most companies meet their leakage targets, but Southern missed their target in 2005-06, United Utilities in both 2004-05 and 2005-06 and Severn Trent in both 2005-06 and 2006-07 and Thames for the three years to 2005-06.

Ofwat has powers to fine companies that fail to meet their leakage targets. However, instead of exercising these powers, Ofwat has sought legally binding agreements with the companies to spend shareholders' money on additional leakage control activity, rather than this be funded by customers.

For example, in July 2006, Ofwat announced that Thames had agreed to invest an extra £150m, twice as much as the fine the regulator could have imposed, to replace ageing pipes over five years, and similarly, in August 2007 Ofwat announced a legal agreement with Severn Trent that binds the company to achieving its leakage reduction targets for the next three years. The company has underpinned this with a commitment to spend an extra £45 million.

5.1.2 Leakage estimation

The key difference between the water industry and the gas industry is that in the water industry the leakage rates are estimated based on the water balance, i.e. the difference between consumption and supply, rather than using a formula based on network characteristics and assumed leakage rates of different elements.

The actual amount of leakage is not known perfectly and cannot be measured directly across a whole network, but rather estimated. The overall approach is to measure the amount of water supplied into the distribution system and subtracting the amount used by customers. The challenge is that a large number of customers are not metered at all and only subject to estimated demand. Hence, although leakage estimates are based on reconciliation of supply and demand data in the network, it is subject to consumption estimates. Companies' estimates of unmetered customers' consumption vary by up to 31 per cent. OFWAT is encouraging companies to improve the quality of estimates of unmetered domestic consumption and to resolve uncertainties in estimates.

Noting that the "flow balance" is the method for estimating leakage, there are two ways in which the flow balance is used:

5.1.2.1 The total integrated flow method

In this case, companies measure the amount of water entering distribution systems and the amount that has been used by metered customers. The difference between these amounts is the total of

i. the amount used by unmetered customers,

ii. own use (operational) or taken without charge (for example from fire hydrants),

iii. leakage.

Subtracting estimates of the first two elements then leaves a remainder, which is taken to be the amount lost through leakage.

For example, in 1999-2000 (OFWAT/NAO study):

- Companies put into supply 15.6 million cubic metres a day
- Metered customers used 5.3 million cubic metres a day
- The balance was 10.3 million cubic metres a day
- Estimated own use or taken without charge was 0.2 million cubic metres a day
- Estimated use by unmetered customers was 6.8 million cubic metres a day
- ➢ Estimated leakage was therefore 3.3 million cubic metres a day (21.1%)

This estimation process is hampered by the fact that nearly half of all water consumption is by unmetered customers (almost entirely domestic) and the leakage estimate is sensitive to the estimated consumption.

OFWAT can challenge companies to explain their estimates of consumption by unmetered customers where they appear to be out of line with those of other companies. The UK Water Industry Research organisation provides a best practice framework that companies are directed to use. In the gas industry there is a table that sets the initial estimate of usage for new build properties.

5.1.2.2 The DMA night flow method

To combat the issues associated with the integrated flow method and to provide a second estimate, the concept of night flow for a smaller area called a District Metered Area (DMA) is also used.

A “district” is a specific area of the distribution network that can be isolated by boundary valves, allowing accurate measurement of water entering and leaving. An issue worth exploring is whether there is an equivalent in the gas network context, noting that the Demand Estimation Sub-Committee carry out monitoring of consumers’ demand.

This is used in an analysis of water flow and pressure at night (e.g. 3-4 AM) when usage is minimum to estimate leakage within the overall district. Leakage teams close boundary valves around the DMA and take very accurate readings at these times, which is generally when night flow is at its lowest, and the percentage of the flow made up of leaks is therefore at its highest.

A typical district size is 1000-3000 properties. Essentially, the estimated minimum consumption is subtracted from the net inflow and the balance is deemed to be leakage. This does require a degree of estimation because it is unlikely for all users in a district to have meters (although there is a very strong move in this direction).

There are also a number of emerging methods to estimate the minimum household night consumption above which any supply can be assumed to be leakage. Best practice guidelines in general are as follows:[lx]

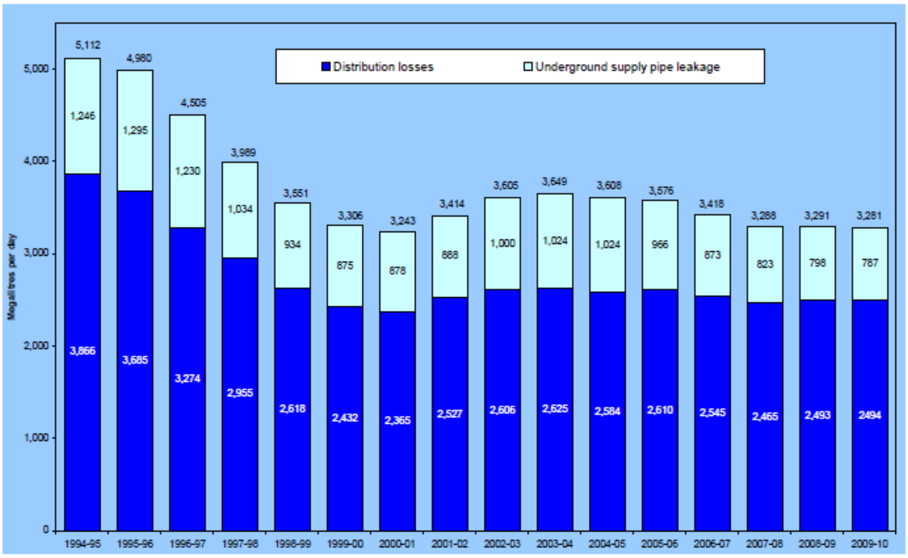
- Consumption monitoring at street or service connection level is appropriate for night consumption analysis, since it is less expensive than monitoring individual households and allows for separating water uses from household leakage and for the breaking down of water uses into single events
- Use of combined meters, where the night consumption component is measured mostly by the (higher precision) volumetric secondary meter and daily consumption is measured mostly by the primary meter.
- Consumption data must be collected with a high resolution (0.1 l/pulse), using a robust emitter (e.g., optical type), and with a short time step (1 minute) for adequately describing night water uses – this indicates the level of sophistication that can be brought to bear on the system.
- The monitoring period should be established taking into account weekly and seasonal scenarios, for a correct identification of possible variations in the minimum flow. In study areas without significant weekly and seasonal variations, the monitoring period may be in the order of one to two months, in areas with larger seasonal variations in consumption, longer monitoring periods may be necessary (up to 12 months).

These give an indication as to the level of care that is possible in establishing the minimum night-time consumption leading to an accurate leakage estimate.

The guidelines also state that the night flow leakage estimate should be reconciled against the leakage estimate derived from the annual water balance (i.e. the integrated flow method). Discrepancies should be distributed across the elements of the system. Current Ofwat guidance is that only discrepancies of less that 5% should be distributed across the components[lxi].

The regulatory regime, which is hands on in terms of targets and expectations, has led to a system which is above average in performance for England and Wales when compared with similar countries.

The performance of the E&W companies over time is shown in Figure 40.



Note:
The apparent rise in leakage levels after 2001-02 is largely attributable to a change in how Severn Trent and Thames assess their water balance data. Both companies were previously under-reporting leakage levels. This means that actual leakage levels in 2009-10 are lower than a decade ago.

Figure 40. Total water industry leakage over time (Source: OFWAT - Service and delivery – performance of the water companies in England and Wales 2009-10)

5.1.3 Scottish Water System

The situation in Scotland is somewhat different. The regulator is the Water Industry Commission for Scotland (WICS, http://www.watercommission.co.uk/), and the system is somewhat closer to the gas industry. These are the key elements of the system:

Scottish Water operates Scotland's publicly owned network of pipes, mains, and treatment works. It acts as the wholesaler in the market, selling water and sewerage services to suppliers.

The Water Services etc (Scotland) Act 2005 established a framework for competition. It required the separation of Scottish Water's wholesale services from its retail function. It also allowed new **licensed suppliers** to compete in a retail market for business customers (domestic customers are served by Scottish Water which is still a public utility).

WICS are responsible for implementing this framework, and are the licensing authority for the market including provision of supplier licences.

There are over 130,000 business customers in Scotland (all customers who are not households) eligible to choose their supplier. Suppliers (licensed providers) are able to compete for the custom of all business customers in Scotland. Suppliers buy services at wholesale from Scottish Water.

The **Central Market Agency** ensures the market functions in a simple and efficient way. The CMA facilitates the transfer of customer information between suppliers. It also calculates the money owned by each supplier to Scottish Water for wholesale services.

The suppliers are only charged for the water used at the consumption point, which is either metered or if unmetered is based on a formula which is presumably similar to that they would apply to their customers, for example, from the 2014-15 code:

The assessed volume will be calculated using the following formulae:

- Assessed water volume (m3 per year) = ((0.0373 x Rateable Value) – 24)
- Assessed sewerage volume (m3 per year) = 95% x ((0.0373 x Rateable Value) – 24)

Hence, the losses in the system are borne by the network operator, Scottish Water in this case. Of course the costs are indirectly passed on to all end-users via the (regulated) price.

WICS regulates the issue of leakage in a fashion similar to OFWAT, stating:

> *"Since 2006, we have agreed with Scottish Water pragmatic annual targets to reduce leakage continually so that it achieves the point where the cost saving of reducing leakage is equal to the economic cost of the water lost. This is known as the economic level of leakage."*

The regulator recognised in the past that leakage rates in Scotland were much higher than those in England and Wales, where water companies made large reductions in the late 1990s.

In this period the leakage estimates were uncertain and the economic level of leakage not clear. By the early 2000s estimates indicated that up to 50% of water was lost through leaks.

Hence, in the last WICS Strategic Review:

> *"Scottish Water was required to make significant progress in estimating the level of leakage and understanding the economics of leakage. It was also required to implement a number of initiatives to improve its understanding of the amount of water consumed by customers and to measure leakage in its distribution system. The Commission asked Scottish Water to provide a reliable estimate of its economic level of leakage (ELL) by December 2008."*

To make this viable in the short term, assuming that the measures would pay in the long term, the short term costs were allowed for in the price setting regime, including £40 million of capital and £16 million of operating costs (in 2003-04 prices) over the regulatory control period.

Since then, WICS sets annual leakage targets, based on the historical reduction rates.

5.1.3.1 Scottish Water's leakage performance

Although Scottish Water reduced its leakage in 2006-07 and 2007-08, it failed to meet its targets in both years. It is reported that the target 840 Ml/day for 2008-09 has been outperformed.

Scottish Water is making progress in understanding and measuring leakage, mainly by setting up DMAs (as described above) that measure flows in local distribution systems. These district meter areas now cover more than 95% of Scotland's population.

Scottish Water submitted a report on its economic level of leakage to WICS in December 2008. However, the WICS "*considers that the report's findings are not robust and intends to work with Scottish Water to improve understanding of the ELLs across Scotland*."

5.1.3.2 Proposals on leakage

WICS states that it "*continues to regard leakage as a priority. It expects Scottish Water first to determine robust estimates of its sustainable ELL and then to achieve that level by the end of the regulatory control period. The Commission considers that a level of leakage that is both economic and sustainable is likely to be well below 500 Ml/day.*"

5.1.4 Best practice in the water industry

A review of companies resulted in a range of activities that represented best practice in the industry on leakage measurement. The most common were the use of extensive district metered areas, the management and analysis of nightflow data and the use of acoustic equipment to locate leaks.

The World Health Organisation has a best practice manual considering all elements of water leakage[lxii]; the key points are illustrated below.

Element	Tool
HOW MUCH **is being lost?**	**WATER AUDIT** Measure components Check production /consumption Recalculate water balance Review records/operating procedures/skills
WHERE **is it happening?**	**PILOT STUDIES** Quantify total losses How much is leakage? — distribution network — transmission mains — reservoirs How much is non-leakage losses? Refine the water balance calculation
WHY **is there water loss?**	**REVIEW NETWORK** *Investigate:* Historical reasons Poor practice/poor QA (Quality Assurance) Poor materials/infrastructure Local influences Cultural/financial/social/political factors
HOW TO IMPROVE **performance?**	**ACTION PLANS/STRATEGY DEVELOPMENT** Update records systems/GIS Introduce zoning/DMAs Monitor water losses and leakage Prioritize areas Address non-physical losses Detect and locate leaks Initiate repair/rehabilitation policy
HOW TO MAINTAIN **the strategy?**	**TRAINING/AWARENESS** Improve awareness Increase motivation Transfer skills Introduce best practice/appropriate technology Give hands-on experience/continual reinforcement Monitor and follow-up action plans /implementation Involve community Consider demand management policy Initiate water conservation programme

Figure 41. WHO best practice guidelines for water leakage

5.2 Offshore oil and gas

The upstream oil and gas industry leakages are quantified in two ways.

First, the amounts of emissions are primarily estimated through the Environmental Emissions Monitoring System (EEMS) process which uses estimation techniques which are in some ways similar to the GDN leakage model but with the application of age factors[lxiii].

Second, the numbers of leaks are reported as part of the safety regime.

5.2.1 EEMS and the emissions inventories

The national atmospheric emissions inventory includes elements of methane leakage from offshore oil and gas installations and pipelines as well as onshore assets. A summary of the elements is below[lxiv]. Note that T2 means "Tier 2", i.e. national data are used and T3 means "Tier 3), i.e. site-specific data are used.

3.3.2.1 Source Category Description

Emissions sources	Sources included	Method	Emission Factors
	1B2a: Oil Production - well testing	T2	CS, PS
	Oil Production – process and fugitive emissions	T2	CS, PS
	Oil Production – offshore oil loading	T3	CS
	Oil Production – onshore oil loading	T3	CS
	Refineries (drainage)		
	Refineries (tankage)		
	Refineries (process)		
	Oil Production - oil terminal storage	T2	CS
	Petroleum processes		
	Petrol Stations (Petrol Delivery)		
	Petrol Stations (Vehicle Refuelling)		
	Petrol Stations (Storage Tanks)		
	Petrol Stations (Spillages)		
	Petrol Terminals (Storage)		
	Petrol Terminals (Tanker Loading)		
	Refineries (Road/Rail Loading)		
	1B2b: Gas production –well testing	T2	CS, PS
	Gas production – gas terminal storage	T2	CS, PS
	Gas production – process and fugitive emissions	T2	CS, PS
	Gasification processes		
	Gas transmission network leakage	T3	CS
	Gas distribution network leakage	T3	CS
	Gas leakage at point of use	T3	CS
	1B2c: Oil production – gas venting	T3	CS, PS
	Gas production – gas venting	T3	CS, PS
	Oil production – gas flaring	T3	CS, PS
	Refineries (Flares)		
	Gas production – gas flaring	T3	CS, PS
Gases Reported	CO_2, CH_4, N_2O, CO, NO_x, SO_2, VOC		

Figure 42. Elements of emissions inventory from the oil and gas industry

The estimation methods are summarised below.

Table 3.59 Summary of Data Sources and Estimation methods for 1B2 source categories in the UK GHG Inventory, 1990-2012

Type of facility / source	IPCC source categories	Data Sources and Methods
Offshore oil and gas platforms	[1A1c Other Energy industry: Upstream oil/ gas fuel use (diesel, own gas)]	Primarily based on DECC energy stats, however some gaps in data on gas use (1990-2001) and LPG/OPG use (2003-) are addressed using EU ETS and EEMS data.
	1B2aii, 1B2bii Oil, Gas Production: Upstream facility process and fugitive releases	1998-2012: sum of reported facility emissions for process and fugitive releases (EEMS). 1990-1997 data based on UKOOA 2005 study. Source allocation less certain for earlier years.
	1B2aiii Transport: Offshore loading of oil	1998-2012: sum of reported facility activity and emissions for offshore loading (EEMS). 1990-1997 emissions data based on UKOOA 2005 study. AD estimated assuming CH_4 IEF from 1998 is valid for earlier years.
	1B2ci,ii Venting at upstream oil, gas facilities	1998-2012: sum of reported facility emissions for venting releases (EEMS). 1990-1997 data based on UKOOA 2005 study. Source allocation less certain for earlier years.
	1B2ci,ii Flaring at upstream oil, gas facilities	1997-2012: sum of reported facility activity and emissions for flaring (EEMS). 1990-1996 emissions data based on UKOOA 2005 study, with mass-based AD estimated from the DECC volume time-series, assuming the same oil:gas split as in EEMS 1997, and aggregate oil and gas flaring volumes 1990-2012 (DECC 2013).
Offshore floating production and storage vessels, well testing rigs	[1A1c Other Energy industry: Upstream oil/ gas fuel use (diesel, own gas)]	[As above for oil and gas platforms]
	1B2ai, 1B2bi Oil, Gas Exploration: well testing	1998-2012: sum of reported facility activity and emissions for well testing (EEMS). 1990-1997 emissions data based on UKOOA 2005 study. AD estimated assuming CO_2 IEF from 1998 is valid for earlier years.

Figure 43. Estimation methods for methane emissions in the oil and gas industry

As noted in the table above, many of the emissions estimates are derived from operator-reported activities and emissions from the upstream oil and gas facilities that are regulated by the DECC Offshore Inspectorate. Oil and gas operators submit annual source-specific emission estimates to DECC in the Environmental Emissions Reporting System (EEMS); reporting of emissions is mandatory for all offshore facilities

Emissions from upstream oil and gas production facilities, including onshore terminals, are estimated based on operator reporting via EEMS, regulated by the DECC Offshore Inspectorate and developed in conjunction with the trade association Oil & Gas UK (formerly the UK Offshore Operators' Association, UKOOA). The EEMS data provides a detailed inventory of point source emissions estimates, based on operator returns for the years 1995-2012.

The EEMS dataset are considered the primary dataset to inform UK GHG inventory estimates as they are source-specific, complete (cover all emission sources on each facility), transparent (activity data and emissions data reported for most sources) and have been reported by operators for around 15 years.

The EEMS guidance provides some interesting insights relevant to this study. First of all it ensures avoidance of inaccuracies due to differences in temperature and pressure. From the guidance[lxiii]:

> *Mass is the preferred physical quantity for reporting gas emissions because of its independence of temperature and pressure. All gas amounts reported to EEMS are masses, usually in tonnes (t). However, most gas measurements made in the field are volumes at non-standard temperatures and pressures.*
>
> *If volumes are measured under non-standard conditions they are converted to standard conditions using Boyle's Gas Law based on the Ideal Gas Law:*

$$V_{std} = (P_{obs} \times V_{obs} / T_{obs}) \times T_{std} / P_{std}$$

$$= (P_{obs} \times V_{obs} / T_{obs}) \times 288.15/101.325 \times 1035.3$$

Where

- Pobs is the observed pressure (Pa)
- Vobs is the observed volume (m3)
- Tobs is the observed temperature (K)
- Pstd is the standard pressure (Pa)
- Vstd is the standard volume (sm3 (15C))
- Tstd is the standard temperature (K)

This ensures that the reporting of leakage estimates takes account of the prevailing conditions.

DECC and Oil & Gas UK, 2008. *EEMS. Atmospheric emissions calculations*. Issue No. 1.810a. London: Department for Energy and Climate Change. Available from: http://og.decc.gov.uk/assets/og/environment/eems/tech-docs/atmos-calcs.pdf [Accessed 26 July 2012].

The leakage estimation methodology is also explained in the guidance notes. For "fugitive emissions" i.e. leaks from system components such as joints, values and pump seals, the estimate is based on:

i. The number of the different types of components,
ii. The application of a default fugitive emission for each component,
iii. And, in contrast to GDN estimation models, an "age factor" for each component.

Typical values of the latter two items are illustrated below. The data were arrived at through an industry-wide consultative exercise. Emission factors and calculation methodologies are approved by the UKOOA Atmospheric Emission Work Group based upon UK studies, Oil and Gas Producers Association, American Petroleum Institute and the US Environmental Protection

Agency. In 1998 the system was the subject of an external review by specialists at AEA Technology.

Location HC Type	Onshore Light Crude	Onshore Heavy Crude	Onshore Gas	Offshore All
Connections	1.44	0.070 1	2.40	0.946
Valves	11.7	0.114	33.9	4.52
Open-ended	10.6	1.36	9.11	8.94
Pumps	2.79	0.026 3	101	1.72
Other	66	0.613	42.7	60.9

Commissioning Date	Age Adjustment Factor
After 1988	1.0
Between 1980 and 1988	1.3
Before 1980	1.5

Figure 44. Default emission factors for fugitive emissions from plant components ($kg.yr^{-1}.compnent.^{-1}$)
Figure 45. Installation/terminal age adjustment factors for fugitive emissions

So for example, for each plant component type and each emission gas, the mass of emissions released per year would be calculated as follows:

Mem(i) = Nc * Ec * Adage* Cwt(i)/105 9.1

Where

- (i) is an emission gas
- Mem(i) is the mass of emission gas (i) released by a particular plant component type (tonnes)
- Nc is the total number of plant components of a particular type
- Ec is the fugitive emission factor for the component type, location and hydrocarbon type (kg/component-yr)
- Adage is the age adjustment factor based on the commissioning date of the installation or terminal
- Cwt(i) is the component weight percentage of emission gas (i) based on the component mole percentage of vent gas (taking account of the fact that for example the gas vented may not be 100% methane)

The two relevant points of difference in practice for this study are:

i. The temperature and pressure adjustment

ii. The use of age adjustment factors for different parts of the system

The safety related reporting is described below.

5.2.2 Reporting of pipeline and riser loss of containment incidents (PARLOC)

The PARLOC process was conceived after Cullen inquiry into the Piper Alpha incident. All leak related incidents to be reported to the HSE and documented; the PARLOC process aggregates and reports this information.

An interesting feature about the process relates to the uncertainty around complete details of the UK offshore pipeline network, which is of relatively low complexity compared to GDNs.

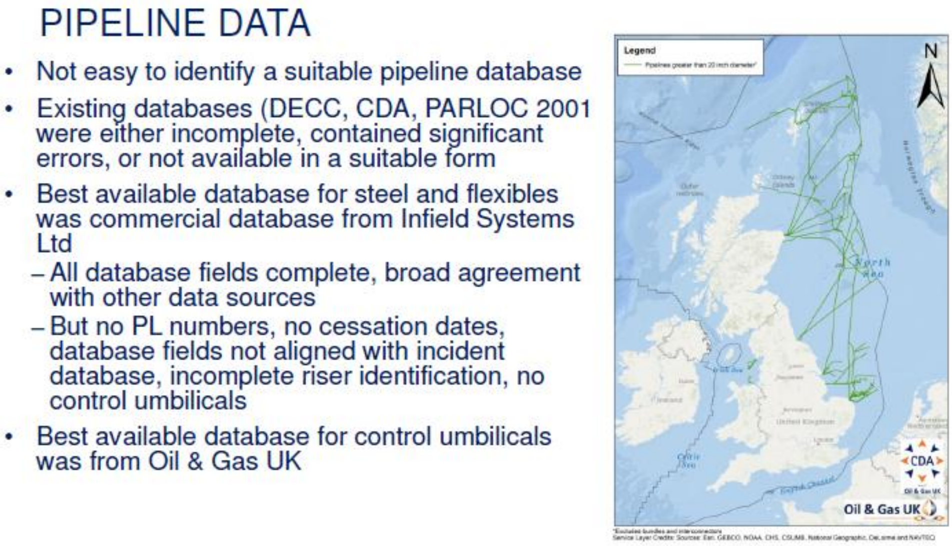


Figure 46. Summary of pipeline details from EI/OGUK presentation[lxv]

5.2.2.1 PARLOC summary results

Some key results are illustrated below.

RESULTS - STEEL PIPELINES & RISERS

INCIDENTS	Steel Pipelines		Steel Risers	
	Reported	Estimated	Reported	Estimated
Totals	85	92.7	13	19.66

PIPELINE	Steel Pipelines		Steel Risers	
	Number	km*years	Number	riser*years
All diameters	1,372	219,165	1,130	11,997

	Steel Pipelines		Steel Risers
	Estimated frequency (per km*year)		Estimated frequency (per km*year)
All diameters		4.23E-04	Included in pipelines

RESULTS - FLEXIBLE PIPELINES & RISERS

	Flexible Pipelines		Flexible Risers	
	Reported	Estimated	Reported	Estimated
All diameters	50	55.2	20	24.55

	Flexible Pipelines		Flexible Risers	
	Number	km*years	Number	riser*years
All diameters	1,288	10,133	440	3,974

	Flexible Pipelines		Flexible Risers
	Estimated frequency (per km*year)		Estimated frequency (per km*year)
All diameters		5.47E-03	Included in pipelines

Figure 47. Summary of pipeline details from EI/OGUK presentation[lxv]

As noted by the HSE and Mott MacDonald[lxvi], the focus of this process is the estimation of the number and frequency of leaks. They state:

> *"The Incident database does not provide precise information with respect to either the location, or the duration, of loss of containment incidents although the time to locate and register the leak and the time to effect repair is of importance. This lack of information means that an accurate determination of the volume of product lost in each recorded loss of containment incident cannot be reliably estimated. While this may be regarded as being a limitation of the study it is the opinion of the authors that it will generally be more appropriate to develop an estimate of the loss of containment volume from a knowledge of the pipeline operating conditions at the time of a failure and the equivalent hole size rather than on the basis of direct historical data"*

A summary of the 2001 incidents database is illustrated below.

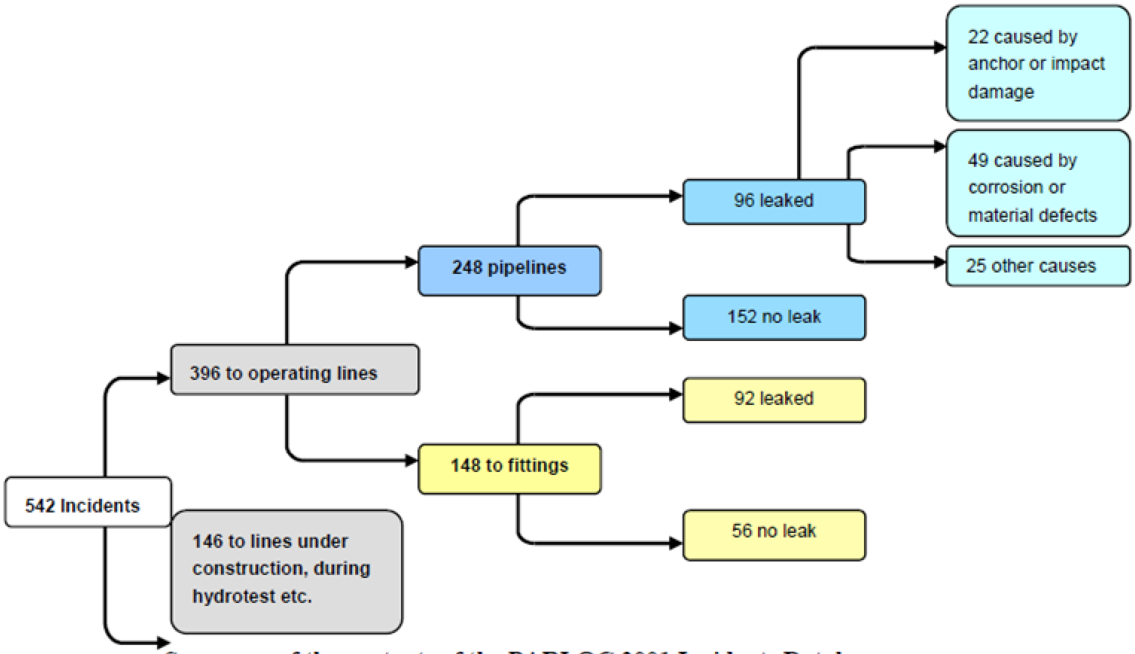


Figure 48. Overview of PARLOC 2001 database

188 incidents resulted in leakage, of which 96 resulted in a loss of containment from steel and flexible pipelines and 92 of the leaking incidents were from fittings associated with the pipeline.

5.2.3 Oil and gas leak detection and repair regimes

There is a well-established oil and gas industry leak detection and repair regime[lxvii]. The first stage is to identify the leaks. The oil and gas processing industry has a systematic approach based on risk and cost–benefit to controlled and fugitive natural gas emissions.

For natural gas leaks, a common approach is to first identify the major processes at the site including compressors, separators, storage tanks, all pipe connections, valves, flanges, vents and open ended pipes. The risks of emissions and leaks are calculated based on component data and each connection is assessed so that a complete inventory can be made and issues dealt with directly. This process is known as leak detection and repair (LDAR).

Historically, this process was completed using calibrated hand-held devices, e.g. flame ionisation detectors or catalytic combustion detectors, using a small probe to scan along all the identified weak points. A typical leak detection would relate to the lower explosion limit concentration (LEL) and may be between 10-100% of the LEL.

On detection of a leak, the regime for repair when above the 'definition' level can vary between 48 hours to 15 weeks, depending on local regulations. This repair schedule can be longer in the case of significant plant shutdown to enable the repairs to be carried out safety, so in these cases, it may be judged practicable to postpone the repair until the next planned shutdown.

The LDAR process has been improved with the use of new technology, specifically the use of infrared (IR) thermal imaging, which is now used in a variety of applications, e.g. leak mapping, including on-shore applications (e.g. shale gas). The standard IR technology is adjusted so that the detector is tuned to a specific wavelength at which a methane leak will show up and a visible gas. This advance has improved the speed of the LDAR process and, depending on the system, whole process areas can be scanned.

Determination of the leak rate is necessary to generate evidence for the need to repair minor leaks and to compile greenhouse gas (GHG) emissions estimates.

From the concentration, tables such as stratified screening value tables are used to estimate the leak from the concentration and component type. This data comes from emissions inventories and so the leak rate determination can carry large uncertainties.

The data is based on a three tier system:

• Tier I is based on pipeline length. It is a very approximate method that does not take account of the presence of specific plant and equipment.

• Tier II is based on the number of major process/stations.

• Tier III is based on individual component counts/events

Direct measurement is also used, typically in relation to the high risk components such as compressors. Direct assessment is achieved using a flow flux principle. The source of leak or whole component is sealed in an enclosure ('bagged' up). A known flow of inert gas is introduced to the gas and the flow of total gas (inert plus leak) is measured at an outlet; knowing the concentration of methane, the mass emission rate of methane can be calculated. This emission rate and the recorded leak concentration at the component can be used to derive an emission factor.

An alternative to bagging is to use a system developed by the Gas Research Institute that samples the leak at a high rate, creating a fast-moving field of air moving at a known flow rate around the immediate source of the leak. The sample flow rate and methane concentration are measured and the mass emission rate of methane can then calculated. This has the major advantage of being portable and much easier to use than the bagging method.

The EA note that, in relation to unconventional gas production:

> *"The use of such methods has been the focus of discussion following the publication of emissions estimates based on the use of ambient monitoring techniques (Pétron et al. 2012). This work suggests that use of an established leak estimate methodology potentially underestimated emissions of methane from a tight gas extraction field by a factor of approximately two. The established methodology based on emission factors and activity estimates indicated that approximately 2 per cent of methane production was lost to the atmosphere, whereas the measurement study combined with the use of dispersion modelling tools indicated that approximately 4 per cent of methane was lost to the atmosphere."*

5.3 Summary of Key Findings

This section reviewed the water and offshore oil and gas industry. The key findings are:

1. The water industry uses difference based methods for estimated leakage. There is an integrated (approximate) approach which looks at the balance between supply and consumption (some of which is estimated) and attributes the balance to leakage. There is also a "district metering area" (DMA) approach which uses a small, well-instrumented district to estimate leakage at times of low consumption (e.g. 4 AM). This could be an approach to use when smart meters have been rolled out to a suitable extent for gas.
2. In England and Wales, the system operator is also the supplier, and experiences a loss of revenue associated with leakage. Hence it would be expected that water companies would operate at the "economic level of leakage", i.e. the level at which any further interventions are more expensive than the leakage saved, but the regulator has had to set targets because historically the appropriate investments were not being made.
3. The offshore oil and gas industry also uses leakage factors that have been developed through analysis and consultation with regulators. These incorporate age factors to account for higher expected leakage rates from old assets. They also have a strict reporting regime for leaks which allows analysis of causes. Finally, they are driving innovations in leak detection that can be used in other sectors.

6 Other issues: iGTs, own use, OFGEM/DECC incentives

6.1 iGTs

Independent Gas Transporters (IGTs) develop, operate and maintain local gas transportation networks.

IGT networks are directly connected to the Gas Distribution Network (GDN) via a Connected System Entry Point or indirectly to the GDN via another IGT. Although domestic, industrial and commercial premises are connected to IGT networks, new housing and commercial developments form the largest share of the IGT market. It is estimated that the number of consumers connected to IGT networks is around 1.5 million.

Under the bilateral Connected System Exit Point (CSEP) Network Exit Agreement (NExA), iGT's are required to provide on an annual basis timely estimates of shrinkage values to large transporters (GDN operators). These values are used to procure extra gas to cover the shortfall due to shrinkage. Any errors in the estimates are reconciled through the Reconciliation by Difference (Rbd) process.

However, according to the IGT arrangements of the Uniform Network Code (UNC), Section C, "IGTS Shrinkage":

> *1. IGTS SHRINKAGE*
>
> *1.1 IGTS Shrinkage*
> *"IGTS Shrinkage" means gas offtaken from a DNO System at a CSEP which is lost from or unaccounted for as offtaken from any directly-connected or indirectly-connected IGT System, including gas lost or unaccounted for by reason of leakage, theft, meter error or meter correction.*
>
> *1.2 Treatment of IGTS Shrinkage*
>
> *1.2.1 At the Nexus Implementation Date there are no arrangements for the identification or estimation of IGTS Shrinkage or for its allocation as among CSEP Users.*
> *1.2.2 It is acknowledged that, as a result, IGTS Shrinkage will be counted as and treated as forming part of Unidentified Gas for the relevant LDZ pursuant to TPD Section H2.6.*

Hence, in the current situation is that any actual shrinkage in the IGT network is treated as Unidentified Gas; the implied assumption is that the IGT networks (comprising approximately a million consumers) is not subject to leakage. Given all the evidence above regarding leakage rates, even in modern infrastructure, it can be reasonably inferred that this is an overly optimistic assumption. Furthermore, it does not put an onus on the IGTs to provide network data and proactively undertake leakage assessments, which is best practice across other industries.

A rough estimate of shrinkage assuming similar behaviour across these systems would be around 2-5% or around £1.4-3.5m per annum based on current baselines.

6.2 Incentives

Review of incentives to reduce NG leakage in GDNs

6.2.1 OFGEM Shrinkage Allowance

This comes under the wider RIIO (Revenue = Incentives + Innovation + Outputs) regulatory framework, which was introduced in April 2013, and is a new performance based model for setting the network companies' price controls which will last eight years. The RIIO mechanism is designed to encourage network companies to:

- Put stakeholders at the heart of their decision-making process;
- Invest efficiently to ensure continued safe and reliable services;
- Innovate to reduce network costs for current and future consumers; and
- Play a full role in delivering a low carbon economy and wider environmental objectives.

A good explanation of how the allowances work is given in OFGEM's Energy Efficiency Directive Assessment Report[lxviii].

They explain that GDNs have performance baselines set for both shrinkage and the separate leakage element. These are set out over a price control period, with expected year to year reductions, based on previous allowances. The GDNs can then earn rewards or face penalties, depending on the outturn against baseline. Note that the outturn is based on the measurement of a model inputs (e.g. average pressures, MEG saturation, network composition) and then the application of the SLM using these inputs, rather than actual measurements of leakage/emissions. The GDNs baselines are based on similar factors, e.g.

The forecast of:

- the length of live mains in a network, over the price control period, by diameter and material;
- the number of services in a network over the price control period;
- the number of above ground installations in a network over the price control period; and
- replacement activity.

The Shrinkage Model assumptions of:

- the percentage split between metallic and plastic service pipes;
- Mono-ethylene glycol (MEG) saturation;
- the impact of replacement activity upon average system pressure (ASP); and
- mains, services and AGI leakage rates

The GDNs have agreed reductions of shrinkage and leakage by 20% over the period Apr 2013-Mar 2021; the figure below indicates the performance to date. However, this is using the same SLM approach and so the same uncertainties and criticisms of the methodology apply.

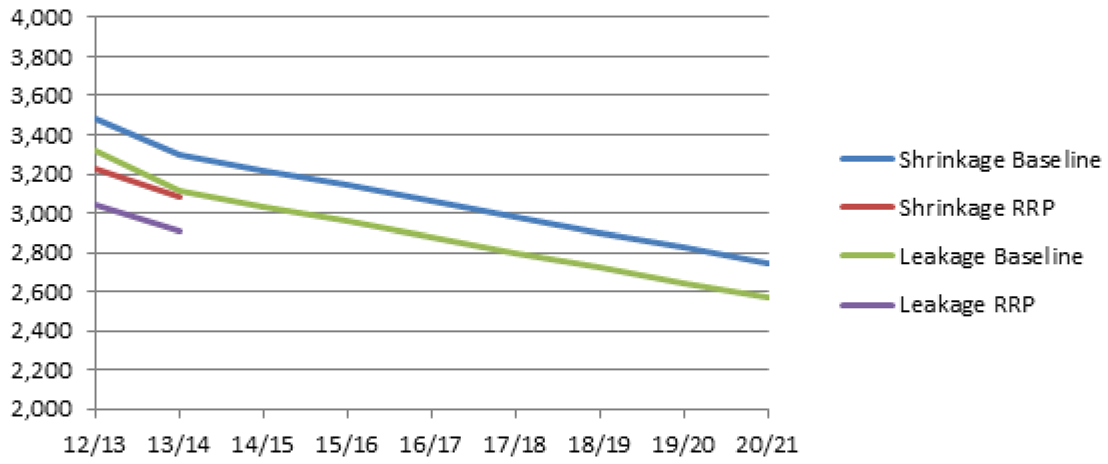


Figure 49. Shrinkage and leakage baseline allowances and actual outcomes (GWh)[lxviii]

The forward allowances are listed below[lxix].

Distribution Network	Correct Allowance (£m 2009/10 prices)							
	t=1	t=2	t=3	t=4	t=5	t=6	t=7	t=8
NGGD EoE	11.80	10.80	10.67	10.44	10.24	10.01	9.88	9.68
NGGD Lon	6.10	5.46	5.35	5.23	5.13	5.02	4.83	4.72
NGGD NW	9.00	8.38	8.27	8.05	7.85	7.62	7.42	7.22
NGGD WM	7.00	6.79	6.79	6.59	6.47	6.37	6.27	6.15
Northern Gas Networks Ltd	10.00	9.61	9.39	8.99	8.87	8.77	8.55	8.35
Scotland Gas Networks plc	5.20	4.80	4.70	4.60	4.47	4.37	4.25	4.14
Southern Gas Networks plc	13.30	13.10	13.00	12.68	12.48	12.28	12.06	11.56
Wales & West Utilities Ltd	8.80	8.62	8.62	8.42	8.32	8.22	8.02	7.82

Figure 50. Forward shrinkage allowances[lxviii]

The incentive for reducing shrinkage is explained below[lxviii]:

> *Under the UNC, GDNs are responsible for purchasing gas to replace that lost through shrinkage. An efficient level of funding has been set out in RIIO-GD1, which can be recovered through Gas Transportation Charges. This provides the GDNs with an incentive to control shrinkage from their networks to avoid having to purchase more gas than they have been funded for. GDNs will also be able to keep a share of any efficiency savings for the remainder of RIIO-GD1.*

Hence, a positive balance can be partially retained by the GDN based on the model. There is a second incentive which only pertains to leakage, explained below[lxviii]:

> *Releases of uncombusted gas have additional environmental impacts. To target this area of shrinkage, an additional output incentive has been introduced for RIIO-GD1. The Environmental Emissions Incentive (EEI) uses the social cost of carbon set by the Department*

of Energy and Climate Change (DECC) to form an incentive unit value. The GDNs are then rewarded or penalised for improvements or deteriorations in leakage performance.

For the RIIO-GD1 price control, Ofgem has also introduced a rolling incentive mechanism which provides eight years of benefit or penalty for the GDNs, irrespective of the timing of investments and delivery of enduring reductions during the price control period.

So in summary:

Shrinkage is funded through the GDN Transportation Charges. The GDNs have two incentives to minimise gas transportation losses:

- *Shrinkage Incentive – incentivises the reduction in volume of gas lost from the network. Licensees receive an allowance to replace gas lost through shrinkage. If licensees need to replace less gas than they have received an allowance for, they share the savings with customers. If they need to spend more than the allowance, then they share any cost over runs with customers.*
- *EEI – provides an incentive to manage the leakage element of shrinkage. Where the reported level of leakage are above* [sic – this is a typo and should be "below"] *the forecast level, the EEI allows GDNs to capture the environmental benefit associated with the reduction in carbon emissions, at the level of DECC's traded cost of carbon. Likewise, if the volume of leakage is higher than forecast, GDNs incur the associated environmental cost.*

Both these mechanisms provide the GDNs with the incentives to reduce the levels of gas lost from the networks. The reward or penalty applied is equal to the non-traded carbon price in the case of the EEI and a reference gas commodity price in relation to the shrinkage efficiency incentive. Baselines for both these incentives were established and agreed through the settlement of the RIIO-GD1 price control, and GDN performance is measured against these baselines with reward for out-performance or penalties for under performance.

As can be seen in the graphs above, the initial baselines are easily achievable and it will be important to review how easy this will become in the future as the allowances reduce.

As explained in the RIIO-GD1[lxx] document, the GDNs are undertaking a number of activities to reduce GDN leakage:

- *Replacement of Metallic Mains & Services – over the RIIO-GD1 period, the GDNs plan to replace a significant proportion of the remaining low pressure metallic mains & services on their network. Mains & Services replacement accounts for over 90% of the total reduction in leakage per annum. The iron mains replacement programme includes the flexibility to select pipes for replacement based on a range of criteria that provide additional customer benefits in terms of financial value and asset performance but also environmental benefits in terms of leakage reduction.*
- *Gas Conditioning – using liquid fogging agents injected into networks at strategic locations to condition the joints on ferrous mains. This swells the lead/yarn joints and restricts the leak path. Used appropriately, this method can reduce the rate of leakage from cast iron pipes by 4% relative to what it otherwise would have been.*

- *Average System Pressure Control – reducing average system pressure to reduce the amount of gas leaking while ensuring a reliable system that meets all demand conditions, including peak winter conditions, is a major objective. Much of the UK gas distribution network is under intelligent pressure control which minimises network pressures and thus leakage. There is an on-going programme to install new pressure control systems for further leakage reduction. There is also an allowance provided in RIIO-GD1 to maintain the existing systems to avoid an increase in pressures which will directly increase leakage.*
- *Network Reinforcement – reinforcements are planned where growth in demand is forecast to avoid the raising of pressures and associated leakage rates. Strategic network reinforcements (non-growth related) are also identified and justified on their ability to achieve further reductions in system pressure and deliver additional reductions in leakage and improvements in asset and network performance.*

The estimated expected benefits over the future periods are illustrated below.

		15-16	16-17	17-18	18-19	19-20	20-21
Mains replacement	£ benefit	£32,940,248	£39,998,151	£47,340,817	£54,527,008	£61,888,267	£69,413,851
	MWh saved	95,304	98,984	93,755	94,793	91,654	92,659
Services relaid and transferred	£ benefit	£8,206,327	£10,002,385	£11,805,287	£13,524,393	£15,240,634	£16,951,748
	MWh saved	18,086	18,606	16,835	16,697	15,736	15,631

Figure 51. Expected benefits of future GDN investment measures

Target set and compared with companies report. Not independent, uses the same calculation without any validation. Does not incentivise alternative approaches in case they come up with higher estimates.

OFGEM define Shrinkage as follows:

> *"Shrinkage is gas lost from the distribution network through leakage, theft and own use gas (e.g. purging the system during system operations or gas pre-heating prior to pressure reduction). In order to compensate for this unaccounted for gas leaving the system, additional gas to that input by Users has to be purchased by the Gas Distribution Networks (GDNs) and the cost passed onto Users. This process is governed by UNC Section N.*
>
> *GDNs therefore have a UNC responsibility to purchase Local Distribution Zone (LDZ) Shrinkage gas. This shrinkage volume is based on an estimate of likely shrinkage in the forthcoming Gas Year using a variety of assumed system parameters known at the time. At the end of the Gas Year, a shrinkage assessment is made using revised known parameters and the differences reconciled with Users. The GDNs therefore have LDZ Shrinkage volumetric allowances within their price control revenue allowances which limits the shrinkage volumes that they are allowed to pass through to Users. GDNs are thus incentivised to minimise shrinkage. If they incur shrinkage volumes below their shrinkage allowances they retain the value of this over the price control period."*

OFGEM further state:

> *"Shrinkage comprises leakage from pipelines (around 95 per cent of gas losses), theft from the GDN network (c. three per cent), and own-use gas14 (c. two per cent).15 Under the*

> *Unified Network Code (UNC), GDNs are responsible for purchasing gas to replace the gas lost through shrinkage, and we fund companies to purchase reasonable levels of gas shrinkage in setting price limits."*

6.2.2 Environmental Emissions Incentive (EEI)

As explained above, a parallel incentive to the shrinkage allowance is applied to the same differential between forecast and outcome **leakage**, whereby the differential (applied only to leakage and not own use and theft) is multiplied by an appropriate price reflecting the carbon price and global warming potential of methane. The following prices are planned:

EEI	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21
£/MWh	62.73	63.66	64.59	65.54	66.55	67.50	68.53	69.61

6.2.3 IMRP (REPEX) programme

A separate incentive relates to the Iron Mains Replacement (IMRP) REPEX programme. Here, OFGEM also fund the GDN at the price review to replace iron mains, which the GDNs agree with the HSE.

They state *"One of the key benefits to the repex programme is a reduction in network losses. As set out in Chapter nine, we also require companies to develop a broad approach to asset management, where they optimise their investment programmes based on an assessment of risk across all asset classes, including environmental risk (eg expected carbon abatement). The shrinkage allowance and EEI incentivise the companies to consider initiatives to reduce shrinkage during the price control period, in addition to the investment schemes that we will fund at the price control designed to address environmental risks."*

According to a summary document[lxxi]:

"A GDN said they supported the HSE's work on reforming the repex programme and that the current approach to funding repex was not encouraging the right behaviours to maintain the current level of safety at value for money."

According to the RIIO final proposals overview[lxxii]:

> *Under the old policy, the HSE required GDNs to replace all iron mains within 30 metres of buildings within 30 years ("30/30" programme). The new policy is referred to as the "three-tier approach". Under the new policy, for tier 1 mains[3] GDNs have to replace the same length of mains as under the old policy but can prioritise replacement based on a wide range of benefits, including reductions in gas losses, operating costs, as well as improvements in safety risk. Tier 1 mains comprise around 80 per cent of the mains population. For tier 2 and 3, in general, the new policy only requires GDNs to replace mains if the pipe replacement is*

[3] The three tiers of pipe diameter are:
Tier 1: 8 inches and below (approximately 80% of all 'at risk' iron pipes)
Tier 2: above 8 inches and below 18 inches (approximately 15% of all 'at risk' iron pipes)
Tier 3: 18 inches and above (approximately 5% of all 'at risk' iron pipes).

justified in cost benefit terms. The exception is high risk tier 2 mains, where there is a mandatory requirement.

At initial proposal (IP), we provided no funding for tier 2 and 3 mains for WWU and very limited funding for NGGD and SGN as we did not consider that they had undertaken their investment appraisal consistent with our appraisal guidance. We have not made any changes in relation to NGN‟s tier 2 and 3 iron mains related outputs relative to IP, as its plan was consistent with our guidance and at IP we proposed to fund it in full.

Since IP, NGGD, SGN and WWU have resubmitted their investment appraisal for tier 2 and 3 mains in a way that is largely consistent with our guidance. In particular, they have submitted plans consistent with our proposed discount period of 24 years to accommodate uncertainty in relation to future network use and the pay-back of network investment. In response to the new information provided by GDNs, we propose to allow additional repex allowances and associated outputs for all three groups. This increase in outputs explains in large part the increase in allowances relative to IP.

In return for the funding levels, we will require GDNs to improve the safety risk performance of their iron mains population by 40 to 60 per cent.

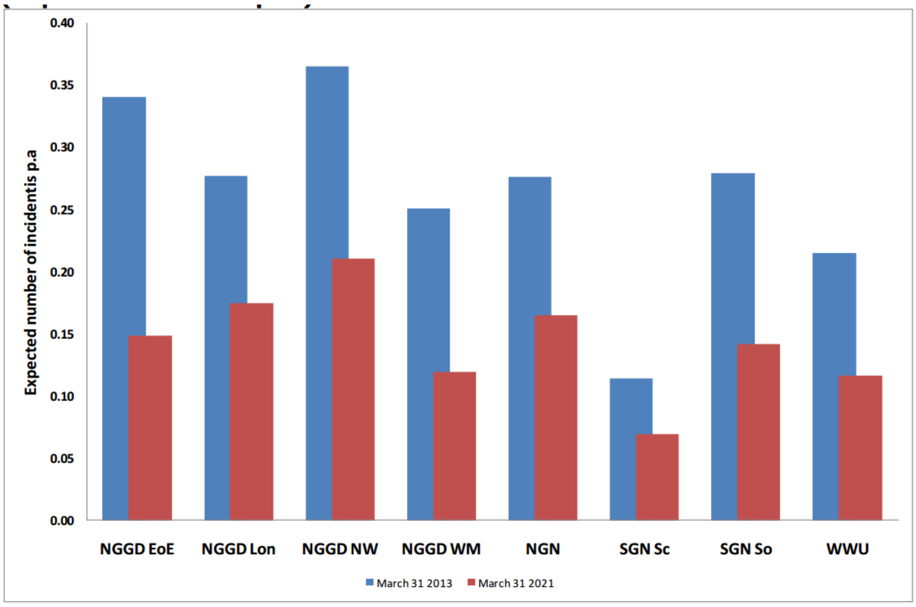


Figure 52. Expected improvements in safety risk over RIIO-GD1 (expected incidents p.a.)

The HSE indicates that there will be a review of the IMRP before OFGEM's RIIO mid-period review in 2016. The plan is for OFGEM to allow incentives in IMRP:

We (OFGEM) will ensure that we allow GDNs to retain the benefits of unit cost outperformance in relation to the delivery of the iron mains programme for the full eight-year period (subject to the efficiency incentive rate), thereby providing strong incentives for GDNs to develop innovative lowcost techniques to address iron mains risk.

The HSE undertook a ten year review of the IMRP[lxxiii]. The explain that the programme was started in 2002 to deal with societal concern around cast iron gas main failures and the associated health and safety risks. The overall objective was to decommission all cast iron mains within 30 metres of property in 30 years ; henc the IMRP is often referred to as the '30/30' programme. They note that:

> *The IMRP accelerated the replacement of cast iron mains to a level that was estimated to be as fast as practicable at that time, given the potential risks faced by society and the resources required. The IMRP excluded steel mains and services from the replacement programme as potential risks from steel, at that time, were considered to be at a lower level than risks from cast iron mains.*

Our analysis of the data indicates that the steel risks are indeed substantially lower.

The cost benefit analysis undertaken found that:

> *the main benefits arising from the IMRP relate to network efficiency (reduced repair costs and reductions in the level of private shrinkage) and environmental benefits (lower emissions). Health and safety benefits, although clearly important, are not material when set against the costs of the programme. However despite what the analysis shows, care must be taken in equating the same monetary amount of the different benefits identified….*
>
> *… The analysis has shown that to date the IMRP has been extremely expensive, given the number of lives potentially saved from it, but this was already known to be the likely outcome when the programme was originally designed. The evidence provided by AESL combined with the CBA suggests that there are a number of options available to restructure the programme that have the potential to deliver significant cost savings in the future. It is critical that any structural changes that may occur to the IMRP in the future be accompanied with a significant improvement in the way in which data is captured and interrogated to inform the implementation of the programme. This will play an important role in optimising the delivery of the IMRP on a year on year basis going forward and would also support any future appraisal / review of the programme.*

Frontier economics also undertook an IMRP review for OFGEM[lxxiv] and their main findings are reproduced below.

4 Shrinkage

The accelerated mains replacement programme is likely to result in a more rapid reduction in shrinkage

Shrinkage estimates reported in GDPCR1 suggest that the accelerated repex programme will reduce shrinkage by 62 GWh per year

Shrinkage volumes forecast in December 2007 final proposals…

	Shrinkage volume (GWh)			
	2009-10	2010-11	2011-12	2012-13
LDZ	Total	Total	Total	Total
East Anglia	286	286	286	285
East Midlands	409	409	408	406
North Thames	396	393	390	386
North West	501	488	484	480
West Midlands	403	393	391	388
Yorkshire	296	292	288	283
Northern	234	230	227	224
Scotland	284	278	272	266
South East	445	433	421	409
Southern	303	298	292	286
Wales North	64	61	60	59
Wales South	170	163	157	153
South West	299	292	285	278
	4,090	**4,016**	**3,960**	**3,904**

…do GDNs now have more accurate shrinkage numbers?

Average annual reduction in shrinkage forecast during GDPCR1 = 62 GWh

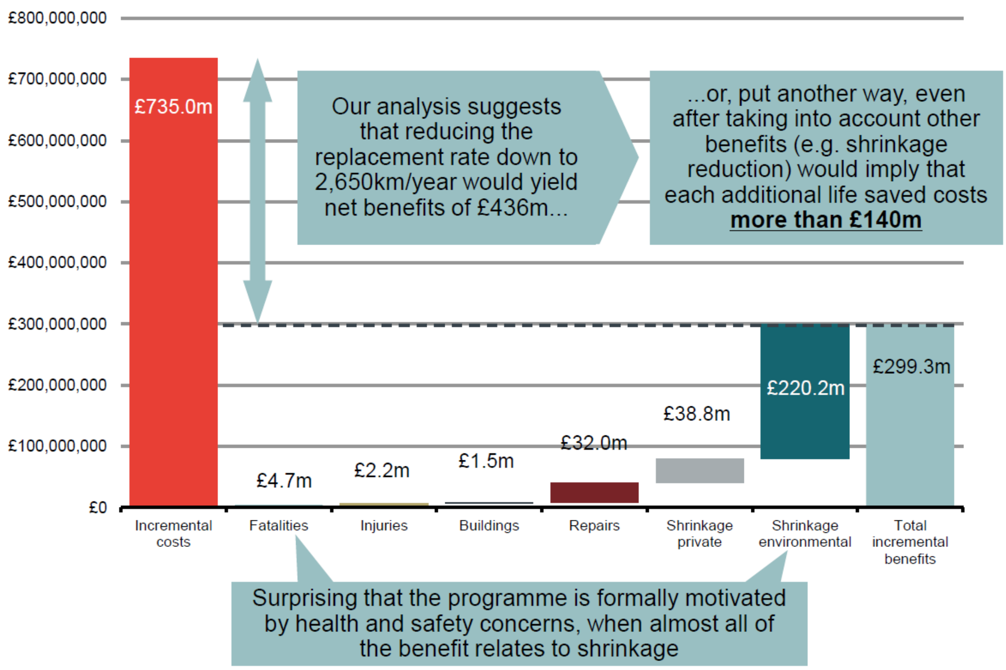
Extrapolating forward linearly, this implies a ~35% reduction in total shrinkage over the course of the repex programme

Again, this is a conservative assumption. In reality, the forecast reductions in shrinkage during GDPCR1 reflect changes in pressure management as well as repex. Therefore unlikely that the repex programme alone will really reduce shrinkage by as much as 35%

A 35% reduction would in turn imply that shrinkage would fall at the slower rate of 48 GWh per year under the counterfactual programme

16 Frontier Economics

Putting this all together, the incremental costs would appear to be much larger than the incremental benefits



19 Frontier Economics

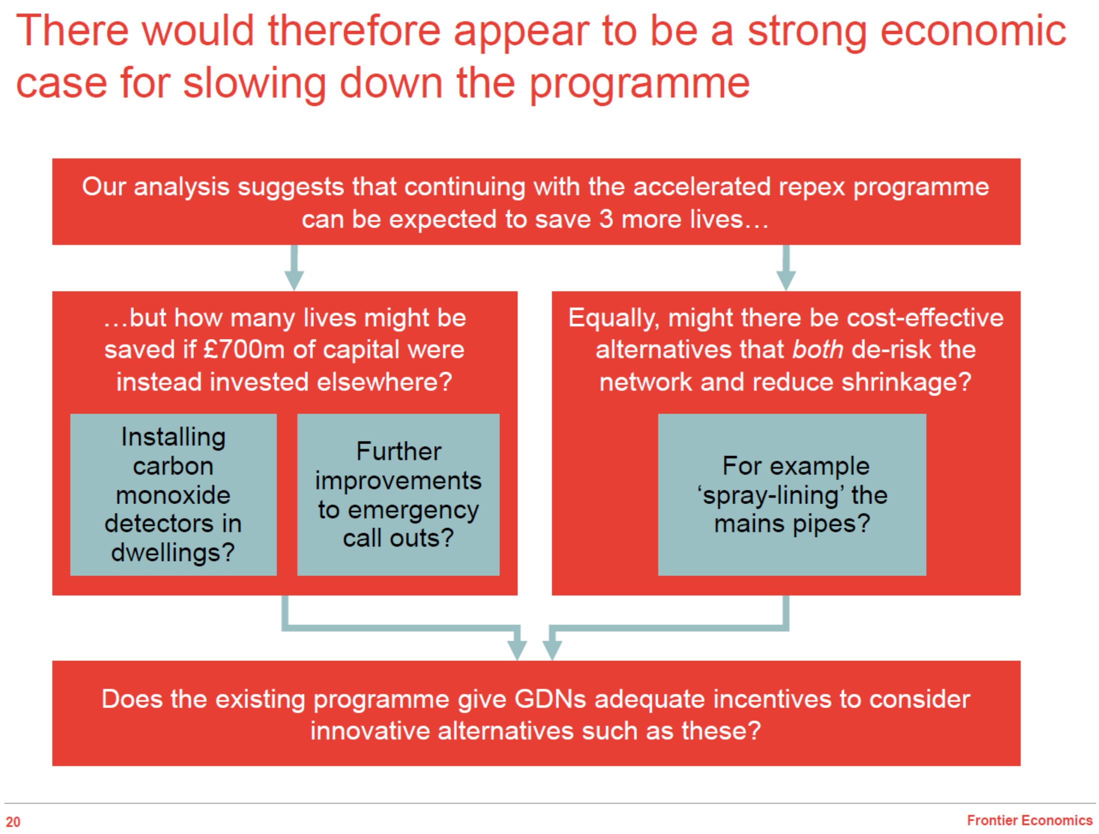


Figure 53. Selected slides on IMRP review

6.2.4 Comments on incentives generally

We note that the estimate of shrinkage and the "actual" shrinkage are essentially based on the same shrinkage model. This results in a situation whereby the use of other methods to calculate actual shrinkage are unlikely to be used as they will introduce uncertainty and potentially lead to a cost to GDNs if these new methods lead to higher shrinkage estimates.

The extent to which this process has improved performance has been assessed. It was found that the main behaviour change was pressure management (most likely because this does not require large scale capital investment but rather minor investments and operational improvements). This means that longer term improvements will be subject to diminishing returns unless other types of interventions are also considered.

According to OFGEM[lxxv]:

> *"From our discussions with GDNs, we understand that their outperformance is primarily a result of investment in improved pressure management. Investment in these systems by GDNs has led to a step change in performance against the shrinkage and leakage allowances. However, we expect GDNs' ability to outperform the allowed targets to diminish over GDPCR1, and indeed to diminish in subsequent review periods. We will need to be diligent in setting companies' shrinkage allowances at future reviews, and set challenging allowances to ensure that customers only finance reasonable gas shrinkage costs."*

An interesting overall finding is that the IMRP was not designed to reduce shrinkage but probably has larger impact than shrinkage allowance and EEI.

This is also noted in the Energy Efficiency Directive Review document[lxviii]

> *Leakage comprises 94% of shrinkage on the gas distribution networks. The single biggest contributor to the GDNs achieving a reduction in leakage over the price control period is their mains replacement work. Although this is driven mainly by safety considerations, the associated reduction in leakage will significantly improve the energy efficiency of the networks and help the GDNs to meet their target of 20% reductions of shrinkage.*

This does appear in a sense to be a double incentive, given that the IMRP is separately funded from the shrinkage allowance.It will be important to try to move towards using “actual” shrinkage to drive the process of managing incentives. OFGEM acknowledge this, stating[lxxvi]:

> *“We remain committed to the use of actual shrinkage data as the basis for reporting shrinkage in RIIO-GD2. We acknowledge respondents' views that there are uncertainties in this area, particularly over the timing of when smart meter data will be available. In response to these views, we intend to modify our proposed licence condition in this area. Rather than introducing a strict licence condition requiring companies to use actual leakage data as the basis for the Environmental Emissions Incentive (EEI) and shrinkage allowance in time for RIIO-GD2, we intend to introduce a licence condition on the GDNs requiring them to report to us (collectively) the following information on a biannual basis:*
>
> - *the status of the smart meter roll out*
> - *their assessment of the suitability of smart meter data as the basis for the shrinkage data*
> - *the steps they are taking to ensure they have access to these data*
> - *how they intend to use these data (eg re-calibrating their shrinkage model).”*

OFGEM’s Energy Efficiency Directive Review[lxviii] outlines other future possibilities for GDNs to improve performance associated with shrinkage, including:

Infrastructure

- *Development of new innovative ways to carry out maintenance and repair on existing infrastructure (Core and Vac Innovation Project, Robotics Innovation Project)*

Low Pressure Distribution Mains

- *Completion of the Health and Safety Executive (HSE) mains replacement programme, and then remediation of metallic mains outside of the HSE mains replacement programme*
- *Investigation into the potential for internal joint repairs (CISBOT Innovation Project)*
- *Optimising average system pressure*
- *Optimising MEG saturation*
- *Design, development, manufacture, installation and commissioning of equipment to Improve MEG saturation (TouchSpray MEG Fogging System Innovation Project)*

Medium Pressure Distribution Mains

- *Completion of the HSE mains replacement programme*
- *Remediation of metallic mains outside of the HSE mains replacement programme*
- *Understanding the impact of pressure upon MP Mains leakage rates, capturing within the National Shrinkage model and then optimising average system pressure (Innovation Project)*

Distribution Services

- *Replacement of metallic services (Serviflex, PE Risers)*

Above Ground Installations

- *Understand venting and leakage rates from AGIs so reduction can be targeted (Innovation Project)*
- *Replacement of above ground installation control systems with equipment that reduces venting*
- *Remediation of leaking AGIs*

Own Use Gas

- *The development of more efficient gas pre-heating systems (Immersion Tube Preheating Innovation Project)*
- *Introduction of metering OUG*

Further Development of the Shrinkage Model

To increase the intelligence of the assumptions and estimations within the model, and building upon the work already being undertaken by the Shrinkage Forum, there are several measures the GDNs are undertaking through the innovation mechanisms and a number of others that have been identified as possible improvements to the model:

- *Including a pressure related MP calculation considering the relationship between pressure and leakage*
- *Embedding / accounting for mains remediation, as well as replacement, within model*
- *Accounting for proactive low pressure repair within model*
- *Accounting for remediation within model*
- *Calculation of own use gas through water bath heaters.*
- *Accounting for improvement in Above Ground Installation (AGI) venting volumes29*
- *Using new equipment to indentify AGI leakage and Stakeholder Engagement to capture improvements*

Investigating the use of Smart Meter Data

The Shrinkage Forum is also exploring new sources of data for the model, including an assessment of whether smart meter data could be used within the model. Of the key data inputs required in the shrinkage model, it is estimated that two could potentially be influenced and improved using smart metering data.

Average System Pressure (ASP)

Smart metering could provide usage data that might assist in the validation of network analysis models, which are used to calculate ASP. Although current network analysis validation policy already requires a high level of accuracy, smart metering could help fine tune the process, especially in small, specific areas of networks that are proving difficult to validate. To facilitate this, there would be a requirement for statistical load research to investigate the relationship between individual customer usage obtained via smart meter readings and the 'assumed fully-diversified' peak six-minute demand required by the Network Analysis modelling process.

Smart metering may also provide the opportunity to improve the pressure management of those networks operating on clocked or drawn profiles, ie. not on intelligent profile control, by providing a more accurate assessment of demand requirements, especially through off-peak periods. This could potentially allow pressure management regimes to be refined and pressures reduced during off-peak periods, both of which would result in lower ASP.

Currently, ASP is calculated using network analysis tools that assume a specified average demand across the year for all networks. Smart metering data will allow this figure to be tested and potentially allow for network specific average demand.

There is the potential that smart metering may reduce demand, most likely during off-peak periods, allowing GDNs to operate those networks fitted with clocked or drawn profiles at lower pressures thereby reducing average system pressures which will, in turn, reduce leakage. The behaviour of customers cannot be forecast with any certainty and this will only be understood once significant volumes of smart meters are installed and a number of years of data compared.

GDNs will also investigate the opportunity to develop an improved understanding of demand patterns, following the introduction of smart metering. Smart metering may also make it easier to identify theft downstream of the Emergency Control Valve e.g. via zero meter reads. The measure of OUG is not likely to be impacted by smart metering.
To fully explore some of these potential benefits, GDNs will consider the practicalities of setting up trials on specific networks to determine if smart metering data can impact on the ASP and the likely scale of any improvement. Any trial will be impacted by the smart metering rollout program and the availability of data in specific geographic areas.

Service Pipe Material Data Quality
Service pipe data is estimated using a combination of mains data and service pipe populations recorded during mains replacement activity. It may be possible during smart meter rollout to update the service type information used in the shrinkage model. This would require the support of suppliers and GDNs will raise this issue as part of supplier engagement on rollout.

It would be very useful to know how these opportunities are being followed up.

6.2.5 Smart metering

The GDNs collectively produced a document in Jan 2015 on the potential benefits of smart meters for shrinkage estimation and reduction[lxxvii].

This was produced in response to a request from Ofgem, following the publication of the SLSM Report in July 2014, that the GDNs consider the potential benefits of Smart Metering in more detail. The report notes that:

"there is currently insufficient data available from Smart Meters to carry out meaningful analysis"

and so they focus on potential benefits, blockers, restrictions and next steps.

At present, GDNs are not able to access Smart Meter data but are fully engaged in the development of the DCC and have provided requirements for data into the process. Due to the requirement to maintain consumer anonymity, GDNs will not have direct access to Smart Meter consumption data through an IT system. A request will have to be submitted for any data and this will need to be aggregated before it is issued to GDNs. Once aggregated, the GDNs could in principle review consumption for particular network sections that are mainly domestic and compare consumption versus supply. This will however only be feasible with full, or a high level of coverage. The document notes that:

> *The Smart Metering roll out in the UK is the only one in the world that is to be Supplier led. In every other country the Networks have installed Smart Meters on an efficient street–by-street basis. Suppliers propose to use a 'customer pull' process targeting first those customers that want the new meters. The fragmented nature of the Supplier led model means that it is highly unlikely that GDNs will have access to Smart Meter consumption data for a complete section of the network until the end of the roll out.*

Further, it notes that two of the ten main inputs for the SLC could be improved and influenced once sufficient smart meter data is available. These relate to ASP and updating service pipe data. Note that the focus seems to be on the small user sector.

Average System Pressure – Smart Metering could provide usage data that might assist in the validation of network analysis models, which are used to calculate average system pressures.

Although current network analysis validation policy already requires a high level of accuracy, Smart Metering could help fine tune the process, especially in small, specific areas of networks that are proving difficult to validate. To facilitate this, there would be a requirement for statistical load research to investigate the relationship between individual customer usage obtained via Smart Meter readings and the 'assumed fully-diversified' peak six-minute demand required by the Network Analysis modelling process.

Smart Metering may also provide the opportunity to improve the pressure management of those networks operating on clocked or drawn profiles i.e. not on intelligent profile control, by providing a more accurate assessment of demand requirements, especially through off- peak periods. This could potentially allow pressure management regimes to be refined and pressures reduced during off-peak periods, both of which would result in lower average system pressures.

Currently, average system pressures are calculated using network analysis tools that assume a specified average demand across the year for all networks. Smart Metering data will allow this figure to be tested and potentially allow network specific average demands to be used.

The GDNs will consider the practicalities on trials on particular networks, depending on the availability of data. An approach similar to the water network DMA approach might be suitable.

> *SGN are currently running two parallel, NIA funded, feasibility studies into the requirements of trialling Real-Time Networks within SGN's distribution zones. At this stage, the relevance of Smart Metering in this area is unknown as the feasibility studies look to map the validity of various elements of sensor/metering technology requirements.*

As explained before, Service Pipe Material Data is estimated using a combination of mains data and service pipe populations recorded during mains replacement activity. It ought to be possible during Smart Meter rollout to update the service type information used in the SLM model. This would of course require collaboration between Suppliers and GDNs. The opportunities to improve the SLM based smart meter roll-out are summarised in the figures below.

Component of model	Input	Opportunity from Smart Metering	Data Required	Action	Cost	Benefit / Restrictions
Low Pressure Leakage	Pressure data	No impact on recorded data – Smart Meters do not have the ability to record pressure and would require a pressure sensor before the regulator for this to be of any use if they did.	NA	NA	NA	NA
	Average System Pressure	This is currently calculated using a combination of recorded pressures and network analysis models. Data from Smart Meters could be used to validate the accuracy of these models	6 minute flow data	The GDNs have already fed in the request for this data to be made available	tbc	**Benefits** **Potential to :-** • Fine tune the validation of network analysis models • Refine pressure management • Validate the average demand used to calculate average system pressures **Restrictions** • Requires high coverage of Smart Meters to provide meaningful results • Potentially leakage forecasts could increase • Difficult to assess on medium/large networks

Component of model	Input	Opportunity from Smart Metering	Data Required	Action	Cost	Benefit / Restrictions
	Customer Numbers	No impact – customer numbers already known and held by Xoserve. Supplier led roll out means there is very limited opportunity to determine shipperless sites from installation of gas meters	NA	NA	NA	NA
	Mains pipe material / length	No impact	NA	NA	NA	NA
	Service pipe material	Possible opportunity to collect data on service types; however, this would require Suppliers recording service pipe material during Smart Meter roll out and providing this information to the GDNs	Service pipe material to be recorded by Suppliers on roll out and provided to GDNs	Engage with Suppliers to establish if the collection and transfer of this information is feasible as part of roll out	Unknown	Low pressure services currently account for 16-22% of low pressure leakage, mostly due to steel services. Populations are estimated in the shrinkage and leakage model. Improvements would be expected to be seen as soon as roll out commences in 2017 with full benefit on completion of roll out
	Gas quality information	No impact - Smart Meters will not measure gas quality information	NA	NA	NA	NA
	MEG Concentration	No impact – Smart Meters will not have the functionality to measure MEG concentrations	NA	NA	NA	NA

Component of model	Input	Opportunity from Smart Metering	Data Required	Action	Cost	Benefit / Restrictions
Medium Pressure Leakage	Pipe material / length	No impact – the introduction of Smart Meters will not provide additional information on the makeup of the medium pressure network	NA	NA	NA	NA
AGI Leakage / Venting	AGI Numbers / Types	No impact – Smart Meters will not provide additional information with regards to AGI numbers / types and venting	NA	NA	NA	NA
Interference Damage	Number of Incidents	No impact – Smart Meters will not impact on the number of incidents that occur	NA	NA	NA	NA
Own Use Gas		No impact as in the current model this is a factor of throughput	NA	NA	NA	NA
Theft of Gas		No impact as in the current model this is a factor of throughput	NA	NA	NA	NA

Alternative to the Shrinkage and Leakage Model – Monitoring Gas In vs Gas Out

The same document notes that the GDNs "*consider that the SLM is fit for purpose and is currently the most appropriate mechanism for evaluating leakage and shrinkage.*"

In the long run it might be possible to replace the current SLM which uses activity factors with a model which balances input versus offtake and records the difference. Three options of such a system have been considered in the review:

- Offtake Metering In, Smart Metering Out – Full Coverage
- Offtake Metering In, Smart Metering Out – Representative Networks
- Offtake and Governor Metering In, Smart Metering Out

An important factor in choosing an approach is understanding the level of coverage need to obtain statistically valid results. The GDNs therefore propose to:

commission a trial project utilising innovation funding to obtain a better understanding of the feasibility of each of these three options. At an early stage, GDNs will liaise with Suppliers to influence the Smart Meter roll out as much as possible to maximise the installation of Smart Meters on trial networks and, wherever possible, utilise Smart Meters that have already been rolled out. However, Smart Meter rollout is Supplier led and GDNs will require the support of the wider community in order to realise the potential benefit of any trials.

They make an important point on accuracy:

It should also be noted that fully electronic meters are only required to be accurate to ±2%[4]*, and diaphragm meters to accuracy of 3%. Current shrinkage / leakage levels are currently modelled to be approximately 0.6% of throughput, therefore the inherent error in meter readings to provide actual demand data could be greater than the actual shrinkage levels. However, this error should be mitigated by sample size once a representative population is achieved.*

They note that:

There is a concern, however, that a 'gas in vs gas out' model would make it harder for GDNs to influence shrinkage, particularly the leakage element, as there would be reduced clarity regarding the source of the lost gas.

We agree, hence the need for an updated experimental study like the 2002 one will not be negated by the onset of widespread smart metering.

They also note with respect to theft:

Currently, Shrinkage only includes what is deemed 'transporter responsible' theft, which is estimated to be only a small proportion of overall theft. Due to its nature, the level of theft is

[4] The accuracy of water meters is defined by the The Measuring Equipment (Cold-water Meters) Regulations 1988 as follows

Flowrate range	**Prescribed limits of error on passing as fit for use for trade**	**Prescribed limits of error in relation to the obliteration of the stamp or mark**
From the transitional flowrate (Qt) to the maximum flowrate (Qmax) inclusive.	2 per cent of quantity delivered, in excess or in deficiency.	2.5 per cent of quantity delivered, in excess or in deficiency.
From the minimum flowrate (Qmin) up to, but not including, the transitional flowrate (Qt).	5 per cent of quantity delivered, in excess or in deficiency.	6 per cent of quantity delivered, in excess or in deficiency.

unknown but it could be of equal or even greater magnitude than the level of leakage; this would provide a significant obstacle to being able to separate out the sources of 'unaccounted for' gas in a 'gas in vs gas out' model. Carrying out assessments at different times of the year may help with regard to this; the level of leakage is likely to be fairly flat throughout the year, but the level of theft is likely to follow a seasonal profile.

And with respect to calorific value:

In a 'gas in vs gas out' model, consideration would need to be given to the units in which the comparison is carried out. Errors associated with calorific values and standard pressure and temperature correction could be significant if comparing energy values. This will have an influence on the data required from DCC.

In the GDNs opinion:

In summary, whilst an alternative 'gas in vs gas out' model will be considered, the SLM currently provides the most effective measure of leakage and shrinkage.

The key points are summarised in the figures below.

Table 3 – Options to improve shrinkage measurement by monitoring gas in vs gas out

Metering level options	Requirements	Benefit	Restrictions
Offtake Metering In, Smart Metering Out – Full Coverage	Metering at offtakes – already in place. Statistically valid sample of Smart Meters in place within each LDZ. (GDNs will consider engaging independent consultants to determine a statistically valid sample size.) Data requirements would as a minimum be an annual report of the actual demand.	Little additional cost to the Smart Metering roll out for additional meters. Due to the requirement for a statistically valid sample of meters (with at least one full year of data) to be in place before any calculations of the gas lost could be made, it is expected that any benefit would only be realised late into the roll out programme (estimate 2019/20 roll out to representative samples + one year worth of data); however, this will become clearer once the roll out programmes are shared with the GDNs.	Smart Metering is only applied to U6 size meters therefore excluding larger domestic and commercial/industrial consumers – these consumers (excluding daily metered sites) account for approximately 40% thereby adding significant uncertainty to estimates of lost gas, including theft and own use gas. This would require some form of alternative modelling to determine what is lost gas and how much I&C customers are using. Such an approach whereby shrinkage and leakage are measured at an LDZ rather than sub-network level would significantly impact the way in which shrinkage is managed as there will not be the same level of the granularity regarding the source of the lost gas.

Metering level options	Requirements	Benefit	Restrictions
Offtake Metering In, Smart Metering Out – Representative Networks	Metering at offtakes – already in place Statistically valid sample of smart meters in place within each LDZ. (GDNs will consider engaging independent consultants to determine a statistically valid sample size.) Data requirements would as a minimum be an annual report of the actual demand.	As above; however, instead of waiting for statistically representative sample of Smart Meters across the LDZ before any perceived benefits may be realised, specific networks are targeted in the meter roll out allowing for statistically representative number to be achieved in these networks earlier and thus allowing the measured demand from Smart Meters in these networks to be applied to other similar networks to build an overall expected demand.	Such an approach would require that Suppliers coordinate with GDNs to focus roll out of Smart Meters to specific networks if the full perceived benefits with regards to shrinkage and leakage are to be realised before the completion of the roll out programme. As yet GDNs have not had vision of the roll out plans.

Metering level options	Requirements	Benefit	Restrictions
Offtake and Governor Metering In, Smart Metering Out	Additional meters to be fitted at each network governor. There are approximately 22,000 governors nationally and to achieve the level of metering accuracy required, it is likely to cost at least £50k-£100k per governor to include orifice meter, pressure/temperature correction and power source resulting in a total estimated cost of at least £1.1bn. Smart Metering to measure the gas out. Statistically valid sample of smart meters installed in individual low pressure sub-networks with appropriate metering at the governors.	Identify sub-network specific gas loss, allowing for investigative and targeted action to reduce loss and manage shrinkage and leakage. Ability to start assessing individual sub-networks as soon as statistically representative sample of smart meters are installed and meters are present at all the governors (inlets) to the sub-networks. This learning can then be applied to similar networks before they reach representative numbers of smart meters. (est. 2019/20)	This would require significant investment in flow monitoring, which has not been allowed for in RIIO-GD1 and GDNs have discounted this option as not being feasible.

The GDNs also note that smart meters might result in reduced shrinkage itself:

OFGEM also fund low carbon innovation projects. Current projects that are relevant to this study include

- NG transmission: demonstration of an in-line robotic inspection device for high

Table 4 – Potential for Smart Metering to reduce actual shrinkage

Area	Benefit	Comments
Leakage	Customers use less gas, demand decreases therefore GDNs are able to operate their networks at lower pressures thus reducing the volumes leaked from the low pressure network.	It will not be clear whether a Smart Meter impacts customer's behaviour until significant data is available. When it is available, it will need to be weather corrected to understand the impact. The GDNs are currently engaging the Met Office on a piece of work on weather correction. Information on the actual demand from domestic customers may in some instances help GDNs to optimise some network pressures and thus reduce leakage. However, by the end of RIIO-GD1 a high percentage of the metallic network length will be influenced by intelligent profile control which already minimises pressures based on network performance.
Own Use Gas	None	
Theft of Gas	The use of smart meters should make it quicker and easier to identify sites where theft is occurring as a result of meter bypass i.e. from zero meter reads.	This would require MRPN specific information, which is not currently available to GDNs

pressure networks[lxxviii]

- Northern Gas: Efficient preheating systems[lxxix].
  Performance data from these is starting to become available.[lxxx]
- Scotia gas networks: Robotics - a project to develop new robotic technologies that operate inside live gas networks, in order to repair leaking joints, manage risk of pipe fracture in larger diameter pipes and repair and replace pipeline assets.[lxxxi]

6.3 Summary of Key Findings

The key findings from this section are as follows:

1. The assumptions around iGTs are unrealistic and should be explored in more detail. A rough estimate of the value of shrinkage is 2-5% of the total baseline figure (i.e. £1.4-3.5m).
2. The OFGEM incentives to reduce shrinkage are based on the application of the same SLM model rather than through other verification. They have driven improvements in pressure management but OFGEM indicate that they believe future improvements will be harder to achieve due to the need to go beyond incremental improvements.
3. The most important contribution to shrinkage reduction was actually the IMRP which was instigated for health and safety reasons. There are ongoing debates regarding the future pace of mains replacement and the associated funding.
4. There are many opportunities for innovation, including leak detection and repair, monitoring of AGIs and preheaters, smart metering and real-time estimation of shrinkage and data collection on network configuration (e.g. service pipe materials). These tend to be point source activities; if joined up with a focus on shrinkage they could be more than the sum of their parts.

7 Conclusions and next steps

This report has reviewed:

- The GDN shrinkage and leakage model and its input factors
- Similar models and factors used elsewhere
- Evidence from a variety of leakage measurements
- Practices in other industries
- Regulation and policy around shrinkage

We have found that there are some important anomalies in the shrinkage model; that some of the data are not in line with international estimates and some assumptions border on the optimistic. It has been over 12 years since the last calibration study and it would be reasonable to request another one, especially considering the intervening improvements in technology.

This could be coupled with periodic, non-invasive leak detection activities. This could be co-funded by stakeholders interested in better national emissions inventories (e.g. DECC/DEFRA) and the means to reduce emissions.

More evidence to justify the network composition assumptions should be made available to shippers and other stakeholders to generate more confidence in the SLM.

Annex 1 – key Clauses from OFGEM documents

From **OFGEM Consultation on strategy for the next gas distribution price control - RIIO-GD1 Outputs and incentives**

Shrinkage comprises leakage from
pipelines (around 95 per cent of gas losses), theft from the GDN network (c. three per cent), and own-use gas[14] (c. two per cent).[15] Under the Unified Network Code (UNC), GDNs are responsible for purchasing gas to replace the gas lost through shrinkage,[16] and we fund companies to purchase reasonable levels of gas shrinkage in setting price limits.

2.28. For GDPCR1, we set a cost allowance for shrinkage based on a forecast volume of gas losses (expressed in GWh), multiplied by the day-ahead gas commodity price. The shrinkage allowance provides an incentive for GDNs to outperform the forecast volume of gas shrinkage. If GDNs reported shrinkage is below the allowed volume, they retain the cost saving. Likewise, if reported shrinkage is above the allowed volume, GDNs incur the cost of purchasing the additional gas.

2.30. The forecast volume of gas shrinkage is based on a model of the GDNs' networks ('shrinkage model'). The industry developed the model following extensive research into the relationship between network characteristics (eg asset age, pipeline material, system pressure etc.) and leakage levels. The model also includes a fixed assumption in relation to the level of theft and own use gas on the GDN networks. Under the GDNs' Licence Conditions, the GDNs need to obtain approval of their model from us, and any model changes are subject to consultation with shippers prior to our approval.[18]
2.31. During the price review, the GDNs first estimate and then calculate the modelled level of shrinkage on an annual basis, and GDNs purchase the modelled level of shrinkage and report this level to shippers.[19] As set out above, the GDNs incur the volume risk associated with deviations in the modelled shrinkage volume relative to the allowed level funded within the revenue cap.

2.32. In addition to the shrinkage allowance described above, at GDPCR1 we also adopted an Environmental Emissions Incentive (EEI) with regard to gas leakage (but not the theft or own-use elements of shrinkage). This mechanism ensures that GDNs also consider the carbon costs associated with gas leakage in managing leakage. If GDNs report leakage levels below the forecast level, the EEI allows them to capture the environmental benefit associated with the reduction in carbon emissions. Likewise, if the volume of leakage is higher than forecast, GDNs incur the associated environmental cost.
2.33. At GDPCR1, we adopted an incentive value of around £30/MWh based on the government's carbon valuation at the time.[20] This value reflects the fact that methane leaked to air has an associated environmental cost around 21 times the environmental cost of CO2 emissions.[21] However, to reflect the uncertainty with regard to setting leakage baselines and the high environmental value associated with methane released to air, we adopted a revenue cap and collar equal to ten per cent of the allowed level of leakage.

2.35. To inform our proposals for RIIO-GD1, we have undertaken a review of the companies' performance over the last two years[22] with regard to the shrinkage allowance and EEI. Our analysis indicates that GDNs have achieved significant reductions in the volume shrinkage. In 2009-10 all GDNs beat their leakage and shrinkage allowances.[23] This resulted in the GDNs earning rewards under the EEI of approaching £8m pounds across all GDNs, with some licensees earning over £1m each (equivalent to a return of around 20 basis points on regulated equity).

2.36. From our discussions with GDNs, we understand that their outperformance is primarily a result of investment in improved pressure management. Investment in these systems by GDNs has led to a step change in performance against the shrinkage and leakage allowances. However, we expect GDNs' ability to outperform the allowed targets to diminish over GDPCR1, and indeed to diminish in subsequent review periods. We will need to be diligent in setting companies' shrinkage allowances at future reviews, and set challenging allowances to ensure that customers only finance reasonable gas shrinkage costs.

2.41. As described above, at GDPCR1 the environmental emissions incentive was subject to a revenue cap and collar equal to ten per cent of the forecast cost of leakage. The ten per cent limit equated to a revenue cap and collar of around £11m p.a. for the industry as a whole. At the time, we considered the adoption of a cap and collar was prudent to reflect the uncertainty with regard to forecasting leakage allowance, and thus the potential for high rewards or penalties.

2.42. The potential change to the repex programme following the HSE review – which has implications for the GDNs' ability to forecast future gas losses with certainty – provides a potential rationale for retaining the cap/collar for the EEI. We also need to consider if we should introduce a cap/collar on the shrinkage allowance mechanism for the same reasons, ie to address uncertainty over the repex programme and to mitigate any potential windfall gains or losses from forecasting errors. The downside of introducing caps/collars is that this undermines companies' incentives to minimise losses when the cap/collar is reached.

From: Decision on strategy for the next gas distribution price control - RIIO-GD1 Outputs and incentives

3.42. Shrinkage refers to gas which is lost from the transportation network. It is the dominant element of companies‟ business carbon footprint and accounts for more than 0.75 per cent of GB greenhouse gas emissions.[3] Shrinkage comprises leakage from pipelines (around 95 per cent of gas losses), theft from the GDN network (approximately three per cent), and own-use gas[4] (approximately two per cent). Under the Unified Network Code (UNC), GDNs are responsible for purchasing gas to replace the gas lost through shrinkage.[5]

3.43. We have a two part incentive mechanism in place to encourage the GDNs to manage the shrinkage on their networks to efficient levels.

- The shrinkage allowance funds companies for the cost of purchasing set volumes of gas to account for shrinkage and incentivises the companies to reduce the volume of gas lost from the network and have an efficient purchasing strategy to replace this lost gas.
- The Environmental Emissions Incentive (EEI) additionally incentivises the companies to manage gas leakage to the environment, using an incentive rate based on the social value of carbon.

3.44. We also fund the GDN at the price review to replace iron mains, which the GDNs agree with the HSE. One of the key benefits to the repex programme is a reduction in network losses. As set out in Chapter nine, we also require companies to develop a broad approach to asset management, where they optimise their

investment programmes based on an assessment of risk across all asset classes, including environmental risk (eg expected carbon abatement). The shrinkage allowance and EEI incentivise the companies to consider initiatives to reduce shrinkage during the price control period, in addition to the investment schemes that we will fund at the price control designed to address environmental risks.

3.48. Respondents agreed with our proposals to retain the existing shrinkage incentive. They commented that this represented a continuation of the current incentive structure and considered that this had worked well in encouraging investments to reduce the largest component of GDNs' carbon footprint. Customer groups commented that we should exercise caution when assessing shrinkage baselines to ensure that GDNs do not reap any windfall gains under the incentives.

3.54. We will remove the cap and collar from the shrinkage allowance. Having reviewed responses, we agree that this is not a suitable mechanism to deal with any uncertainty over the repex programme. If the HSE review results in a significant change to the repex programme then we will review the shrinkage and leakage baselines (along with cost allowances associated with repex) and re-set baselines where appropriate.

3.55. We remain committed to the use of actual shrinkage data as the basis for reporting shrinkage in RIIO-GD2. We acknowledge respondents' views that there are uncertainties in this area, particularly over the timing of when smart meter data will be available. In response to these views, we intend to modify our proposed licence condition in this area. Rather than introducing a strict licence condition requiring companies to use actual leakage data as the basis for the Environmental Emissions Incentive (EEI) and shrinkage allowance in time for RIIO-GD2, we intend to introduce a licence condition on the GDNs requiring them to report to us (collectively) the following information on a biannual basis:
the status of the smart meter roll out
their assessment of the suitability of smart meter data as the basis for the shrinkage data
the steps they are taking to ensure they have access to these data
how they intend to use these data (eg re-calibrating their shrinkage model).

Our decision
3.66. We will retain the structure of the EEI and increase its value in line with DECC's non traded cost of carbon. This will result in the following incentive values for each year of RIIO GD1.

Table 3.2: Environmental emissions incentive values (pre-tax, 2009 prices) Year	**2013-14**	**2014-15**	**2015-16**	**2016-17**	**2017-18**	**2018-19**	**2019-20**	**2020-21**
£ per MWh	62.73	63.66	64.59	65.54	66.55	67.50	68.53	69.61

ANNEX 2 GSA details

Consider the square integrable function $f(\boldsymbol{x})$ defined in the unit hypercube $H^d=[0,1]^d$. The decomposition of $f(\boldsymbol{x})$

$$f(\boldsymbol{x}) = f_0 + \sum_{i=1}^{n} f_i(x_i) + \sum_{i=1}^{n}\sum_{j>i}^{n} f_{ij}(x_i, x_j) + \cdots + f_{12\cdots d}(x_1, \cdots, x_d), \qquad (1)$$

where

$$f_0 = \int_0^1 f(x)dx$$

is called ANOVA decomposition if conditions

$$\int_0^1 f_{i_1 \ldots i_s} dx_{i_k} = 0$$

are satisfied for all different groups of indices $i_1,...,i_s$ such that $1 \le i_1 < i_2 < ... < i_s \le n$ [3]. These conditions guarantee that all terms in (1) are mutually orthogonal with respect to integration.

The variances of the terms in the ANOVA decomposition add up to the total variance:

$$D = \int_{H^d} f^2(\boldsymbol{x})d\boldsymbol{x} - f_0^2 = \sum_{s=1}^{d} \sum_{i_1<\cdots<i_s}^{d} D_{i_1 \ldots i_s},$$

where components $D_{i_1 \ldots i_s} = \int_{H^s} f_{i_1 \ldots i_s}^2 (x_{i_1}, ..., x_{i_s}) dx_{i_1} ... dx_{i_s}$ are called partial variances.

Sobol' main effect global sensitivity indices are defined as ratios

$$S_{i_1 \ldots i_s} = D_{i_1 \ldots i_s} / D.$$

Further we will consider sensitivity indices for a single index:

$$S_i = D_i / D.$$

Total partial variances account for the total influence of the factor x_i:

$$D_i^{tot} = \sum_{<i>} D_{i_1 \ldots i_s},$$

where the sum $\sum_{<i>}$ is extended over all different groups of indices $i_1,...,i_s$ satisfying condition $1 \le i_1 < i_2 < ... < i_s \le d$, $1 \le s \le d$, where one of the indices is equal i. The corresponding total sensitivity index is defined as

$$S_i^{tot} = D_i^{tot} / D.$$

Denote $x_{\sim i}=(x_1,...,x_{i-1},x_{i+1},...,x_d)$ the vector of all variables but x_i, then $\boldsymbol{x}\equiv(x_i,x_{\sim i})$ and $f(\boldsymbol{x})\equiv f(x_i,x_{\sim i})$.

$$f_i(x_i)=\int_{H^d} f(\boldsymbol{x})dx_{\sim i}-f_o$$

$$D_i=\int_{H^d}[f_i(x_i)]^2dx_i=\int_{H^d}\left[\int_{H^d} f(\boldsymbol{x})dx_{\sim i}-f_o\right]^2dx_i$$

$$D_i=\int_{H^d}\left[\int_{H^d} f(\boldsymbol{x})dx_{\sim i}\right]^2dx_i-f_0^2$$

Sobol' suggested the following Monte Carlo algorithm for the estimation of $S_y=D_y/D$ $\mathrm{S_y}=\mathrm{D_y}/\mathrm{D}$. Given x and x' being two independent sample points $x=(y,z)$ and $x'=(y',z')$, D_y is calculated using the following formula:

$$D_y=\int f(x)f(y,z')dxdz'-f_0^2 \quad (2)$$

In this case, the Monte Carlo estimator for (2) has a form:

$$D_y\approx\frac{1}{N}\sum_{k=1}^{N} f(y,z)f(y,z')-\left[\frac{1}{N}\sum_{k=1}^{N} f(y,z)\right]^2, \quad (3)$$

where N is a number of sampled points.

Kucherenko et al [4] proposed a new formula for sensitivity indices for sensitivity indices which is especially efficient in the case of indices with small values. He noticed that f_0^2 in (4) can be computed as

$$f_0^2=\int f(x)f(x')dxdx' \quad (4)$$

Substituting (3) into (2) and taking out a common multiplier $f(x)$, we obtained a new integral representation for D_y :

$$D_y=\int f(x)\left[f(y,z')-f(x')\right]dxdx' \quad (5)$$

and the corresponding Monte Carlo estimator:

$$D_y\approx\frac{1}{N}\sum_{k=1}^{N} f(y,z)\left[f(y,z')-f(y',z')\right] \quad (6)$$

[1] Sobol' I, Kucherenko S. Global sensitivity indices for nonlinear mathematical models. Review. Wilmott Mag 2005;1:56-61.

[2]

[3] Sobol' I. Global sensitivity indices for nonlinear mathematical models and their Monte Carlo estimates. Math Comput Simul 2001;55(1–3):271–80.

[4] Kucherenko S, Feil B, Shah N, Mauntz W. The identification of model effective dimensions using global sensitivity analysis Reliability Engineering and System Safety 96 (2011) 440–449

Uncited references

notes

2003 – 4.5 TWh total leakage, National Atmospheric Emissions Inventory.

Cited from
http://www.naei.org.uk/reports.php

Janes, M.; Achur, J.; Martyn, R.; Smithers, D.
and Sarjantson, C., *"Digest of United Kingdom Energy Statistics 2004"*, DTI, 2004.
Moore, S.; Freund, P.; Riemer, P. and Smith, A.,
"Abatement of Methane Emissions", IEA Greenhouse Gas R&D Programme, 1998.

Harrison, M. R., Shires, T. M., Wessles, J. K. and Cowgill, R. M., "Methane Emissions from the Natural Gas Industry" Radian International, Prepared for the EPA in 1996

Melaina, M. W., Antonia, O. and Penev, M. "Blending hydrogen into natural gas pipeline networks: A review of key issues" NREL Technical Report NREL /TP-5600-51995, 2013

AIGA Report "Hydrogen transportation pipelines" AIGA 033/06, 2006

Mruk, S., "Plastic Pipe in Gas Distribution Twenty-Five Years of Achievement", Gas Industries, 1985

ASTM D 2513, Standard Specification for Thermoplastic Gas Pipe, Tubing and Fittings, American Society for Testing and Materials, West Conshohocken, PA.

ASTM D 2447, Standard Specification for PE (PE) Plastic Pipe, Schedules 40 and 80, Based on Outside Diameter, American Society for Testing and Materials, West Conshohocken, PA

ASTM D 3035, Standard Specification for PE (PE) Plastic Pipe (DR-PR) Based on Controlled Outside Diameter, American Society for Testing and Materials, West Conshohocken, PA

ASTM F 714, Standard Specification for PE (PE) Plastic Pipe (SDR-PR) Based on Controlled Outside Diameter, American Society for Testing and Materials, West Conshohocken, PA.

PPI TR-22, PE Piping Distribution Systems for Components of Liquid Petroleum Gases, Plastics Pipe Institute, Irving, TX

Nayyar, Mohinder L. (1992). Piping Handbook , 6th Edition, McGraw-Hill, New York, NY

Iolelchick, I.E., Malyavskaya O.G., & Fried, E. (1986). Handbook of Hydraulic Resistance, Hemisphere Publishing Corporation

AGA Plastic Pipe Manual for Gas Service. (2001). American Gas Association, Washington DC.

CITED REFERENCES

---

[i] http://www.legislation.gov.uk/ukpga/1986/44
[ii] http://www.legislation.gov.uk/uksi/1996/825/regulation/13/made
[iii] https://www.ofgem.gov.uk/ofgem-publications/62913/unc225d.pdf
[iv] https://www.ofgem.gov.uk/sites/default/files/docs/2015/08/joint_decision_letter_0.pdf
[v] http://www.gasgovernance.co.uk/sites/default/files/Joint%20DN%20201415%20SLM%20Review.pdf
[vi] Paul Metro – Pennsylvania Public Utility Commission, "Technical Losses in Natural Gas Transportation, Distribution, and Storage", http://www.naruc.org/international/Documents/Technical_losses_in_natural_gas_transportation_distribution_storage_Paul_Metro.pdf
[vii] Shrinkage Forum, Monday 27 June 2011, UK, available at http://www.gasgovernance.co.uk/sites/default/files/Shrinkage%20Forum%2027%20June%202011%20Final.pdf

[viii] Shrinkage Forum Meeting, June 2011, http://www.gasgovernance.co.uk/sites/default/files/Shrinkage%20Forum%2027%20June%202011%20Final_0.pdf
[ix] Review of Northern Gas Networks Leakage Model Modifications To Service Population Calculations, Report Number: 14914, March 2014
[x] http://www.gasgovernance.co.uk/sites/default/files/Independant%20Review%20of%20Leakage%20Model%20Modification%20to%20Service%20Calculations%20(Review%20No%201%20NGN).pdf
[xi] Sobol' I, Kucherenko S. Global sensitivity indices for nonlinear mathematical models. Review. Wilmott Mag 2005;1:56-61.

[xii] Saltelli A, Tarantola S, Campolongo F, Ratto M. Sensitivity analysis in practice. London: Wiley; 2004.

[xiii] Review of Northern Gas Networks Leakage Model Modifications To service Population Calculations, March 2014.
[xiv] Leakage Model Modification No 3 Report Report on the Consultation on Proposed Modifications to the Leakage Model, Scotia Gas Networks, June 2012.
[xv] "Handbook of Polyethylene Pipe" 2nd Ed, Published by the Plastics Pipe Institute, Available from: http://plasticpipe.org/publications/pe_handbook.html
[xvi] ASTM D 2737, Standard Specification for PE (PE) Tubing, American Society for Testing and Materials, West Conshohocken, PA
[xvii] IEA GHG R&D Report "Reduction of CO2 emissions by adding hydrogen to natural gas" Report number PH4/24, 2003
[xviii] Design of PE piping systems, http://plasticpipe.org/publications/index.html
[xix xix] Klopffer, M.H. and Flaconnèche, B. (2001) Transport Properties of Gases in Polymers: Bibliographic Review. Oil & Gas Science and Technology, 56, 3, 223-224.

[xx] Flaconnèche, B., Martin, J. and Klopffer, M.H. (2001) Transport Properties of Gases in Polymers: Experimental Methods. Oil & Gas Science and Technology, 56, 3, 245-259.
[xxi] Flaconnèche, B., Martin, J. and Klopffer, M.H., (2001) Permeability, Diffusion and Solubility of gases in Polyethylene, Polyamide 11 and Poly(vinylidene fluoride), Oil & Gas Science and Technology, 56, 3, 261-278
[xxii] Kulkarni, S.S. and Stern, S.A. (1983) The Diffusion of CO2, CH4, C2H4 and C3H8 in Polyethylene at Elevated Pressures. J. Polym. Sci.: Polym. Phys. Ed., 21, 441-465
[xxiii] Naito, Y., Mizoguchi, K., Terada, K. and Kamiya, Y. (1991) The Effect of Pressure on Gas Permeation through Semicrystalline Polymers above the Glass Transition Temperature. J. Polym. Sci.: Polym. Phys. Ed., 29, 457-462.

[xxiv] Memari, P., Lachet, V. and Rousseau, B., (2015), Gas Permeation in Semicrystalline Polyethylene as Studied by Molecular Simulation and Elastic Model, Oil & Gas Science and Technology, 70, 227 - 235
[xxv] AGA Plastic Pipe Manual for Gas Service. (2001). American Gas Association, Washington DC.
[xxvi] Michaels, A.S. and Bixler, H.J. (1961) Flow of Gases through Polyethylene. J. Polym. Sci., 50, 413-439
[xxvii] http://www.gasgovernance.co.uk/sites/default/files/Shrinkage%20Forum%2017%20September%202014%20-AGI%20Venting.pdf
[xxviii] http://www.gasgovernance.co.uk/sites/default/files/Leakage%20Model%20Modification%20Draft%20Consultation.pdf
[xxix] Shrinkage and Leakage Model Review, Consultation on Gas Distribution Networks (GDNs). Shrinkage and Leakage Model Review 2014/15, http://www.gasgovernance.co.uk/sites/default/files/Joint%20DN%20201415%20SLM%20Review.pdf
[xxx] http://www.gasgovernance.co.uk/sites/default/files/AdvanticaOUGPresentation23Mar06.ppt
[xxxi] http://corporate.northerngasnetworks.co.uk/innovation/low-carbon-network-innovation-conference/working-for-a-greener-future/pre-heating/
[xxxii] http://corporate.northerngasnetworks.co.uk/innovation/low-carbon-gas-preheating-lcgp-project/performance-data/
[xxxiii] http://www2.nationalgrid.com/UK/Industry-information/Gas-transmission-operational-data/calorific-value-description/
[xxxiv] US EPA, "ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories", available at http://www.epa.gov/climatechange/Downloads/ghgemissions/US-GHG-Inventory-2015-Annex-3-Additional-Source-or-Sink-Categories.pdf
[xxxv] "Natural gas infrastructure and methane emissions", Bipartisan Policy Center, September 2014, http://bipartisanpolicy.org/library/natural-gas-infrastructure-and-methane-emissions/
[xxxvi] Barroso et al., "Evaluation of methane emissions from polyethylene gas distribution systems at medium pressure", Journal of Natural Gas Science and Engineering 1 (2009) 144–153.
[xxxvii] AGA, "Updating the facts: emissions from natural gas systems", https://www.aga.org/updating-facts-emissions-natural-gas-systems-ea-2014-02
[xxxviii] Kirchgessner et al. Estimate of Methane Emissions from the US Natural Gas Industry, Chemosphere, 35, 1997.
[xxxix] Mitchell, C.; Sweet, J.; Jackson, T. A study of leakage from the UK natural gas distribution system. Energy Policy 1990, 18 (9), 809−818.
[xl] Brandt et al., "Methane Leaks from North American Natural Gas Systems", Science 14 February 2014: Vol. 343 no. 6172 pp. 733-735.
[xli] McKain et al, "Methane emissions from natural gas infrastructure and use in the urban region of Boston, Massachusetts", PNAS, February 17, 2015, vol. 112, no. 7, 1941–1946.
[xlii] O'Shea et al, "Area fluxes of carbon dioxide, methane, and carbon monoxide derived from airborne measurements around Greater London: A case study during summer 2012", Journal of Geophysical Research: Atmospheres, 119, 4940–4952 (2014).
[xliii] Phillips et al., "Mapping urban pipeline leaks: Methane leaks across Boston", Environmental Pollution 173 (2013).
[xliv] Jackson et al., "Natural Gas Pipeline Leaks Across Washington, DC", Environ. Sci. Technol. 2014, 48, 2051−2058.
[xlv] http://www.edf.org/climate/methanemaps
[xlvi] JBW Wikkerink, "Improvement in the determination of methane emissions from gas distribution in the Netherlands", 23rd World Gas Conference, Amsterdam 2006.
[xlvii] Lamb et al., "Direct measurements show decreasing methane emissions from natural gas local distribution systems in the United States", Environmental Science and Technology, 2015, 49, 5161-5169.
[xlviii] AGA, Updating the facts: Emissions from natural gas systems, https://www.aga.org/updating-facts-emissions-natural-gas-systems-april-20node4
[xlix] Kruglova and Klimenko, "Fugitive emissions at gas distribution networks: mitigation options", World Gas Conference, 2012.
[l] Mandal et al., "Gas And The Environmental Risks", Energy and Sustainability V: Special Contributions, 2015.
[li] Allen, D., "Methane emissions from natural gas production and use: reconciling bottom-up and top-down

Measurements", Current Opinion in Chemical Engineering 2014, 5:78–83.
[lii] Miller SM, et al.: Anthropogenic emissions of methane in the United States. Proc Natl Acad Sci USA 2013, 110:20018-20022.
[liii] WRI, "Reducing methane emissions from natural gas development: strategies for state-level policymakers", Obeiter and Weber, Working paper, June 2015, www.wri.org/publication/reducing-methane-emissions
[liv] https://opsweb.phmsa.dot.gov/pipelineforum/reports-and-research/cast-iron-pipeline/
[lv] ECI, "Methane UK", http://www.eci.ox.ac.uk/research/energy/methaneuk.php
[lvi] http://www3.epa.gov/gasstar/index.html
[lvii] US EPA, "Improvements Needed in EPA Efforts to Address Methane Emissions From Natural Gas Distribution Pipelines", Report No. 14-P-0324, July 25, 2014, www.epa.gov/oig/reports/2014/20140725-14-P-0324.pdf

[lviii] ABB, "Leakage monitoring: Reducing leakage through effective flow measurement", http://www.abb.com/References/Default.aspx?db=db/db0003/db001466.nsf&c=a054c6eda0dfa79ac1257960004cd6f6
[lix] http://www.nao.org.uk/wp-content/uploads/2000/12/9900971.pdf
[lx] See, e.g., Loureiro et al, 2012, Water 21, http://www.iwaponline.com/w21/01406/w21014060028.htm
[lxi] Tripartite Group, "Best Practice Principles in the Economic Level of Leakage Calculation", https://www.ofwat.gov.uk/publications/commissioned/rpt_com_tripartitestudybstpractprinc.pdf
[lxii] https://extranet.who.int/iris/restricted/bitstream/10665/66893/1/WHO_SDE_WSH_01.1_eng.pdf

[lxiii] DECC/Oil and Gas UK, "EEMS Atmospheric Emissions Calculations", https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/136461/atmos-calcs.pdf

[lxiv] DECC: "UK Greenhouse Gas Inventory, 1990 to 2012", https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/310779/UK_National_Inventory_Report_Main_1990-2012.pdf

[lxv] The Energy Institute/Oil and Gas UK, "Pipeline and riser loss of containment 2001 - 2012(PARLOC 2012)", available from http://www.oilandgasuk.co.uk/PARLOC.cfm

[lxvi] Mott MacDonald, "PARLOC 2001: The Update of Loss of Containment Data for Offshore Pipelines", http://www.hse.gov.uk/pipelines/parloc-2001-report.pdf

[lxvii] Environment Agency: Monitoring and control of fugitive methane from unconventional gas operations
[lxviii] https://www.ofgem.gov.uk/sites/default/files/docs/2015/03/energy_efficiency_directive_report_final.pdf
[lxix] https://www.ofgem.gov.uk/sites/default/files/docs/2015/08/joint_decision_letter_0.pdf
[lxx] https://www.ofgem.gov.uk/publications-and-updates/riio-gd1-final-proposals-%E2%80%93-overview
[lxxi] https://www.ofgem.gov.uk/ofgem-publications/47358/pcrf3-summary-final.pdf
[lxxii] https://www.ofgem.gov.uk/ofgem-publications/48154/1riiogd1fpoverviewdec12.pdf
[lxxiii] http://www.hse.gov.uk/research/rrpdf/rr888.pdf
[lxxiv] https://www.ofgem.gov.uk/ofgem-publications/48376/frontier-repex.pdf
[lxxv] https://www.ofgem.gov.uk/ofgem-publications/48269/gd1-outputs-and-incent.pdf
[lxxvi] https://www.ofgem.gov.uk/ofgem-publications/48259/gd1decisionoutput.pdf
[lxxvii] http://www.gasgovernance.co.uk/sites/default/files/Smart%20Metering%20Report%20-%2030012015%20Final.pdf
[lxxviii] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/gas-network-innovation-competition/national-grid-gas-transmission
[lxxix] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/gas-network-innovation-competition/northern-gas-networks
[lxxx] http://corporate.northerngasnetworks.co.uk/innovation/low-carbon-gas-preheating-lcgp-project/performance-data/
[lxxxi] https://www.ofgem.gov.uk/network-regulation-riio-model/network-innovation/gas-network-innovation-competition/sgn